Table X
EDS Results – Downstream Side Collected Debris

Location	Elements Present		
	Major	Minor	Trace
A	Sulfur, Oxygen, Calcium	----	Aluminum, Phosphorous
B	Sulfur, Oxygen, Calcium	Carbon	Sodium, Magnesium, Aluminum, Silicon, Phosphorous, Iron
C	Oxygen, Iron	Chlorine	Carbon, Aluminum, Silicon, Sulfur, Potassium, Calcium, Titanium, Manganese
D	Oxygen, Iron	Aluminum, Silicon	Carbon, Magnesium, Phosphorous, Sulfur, Chlorine, Potassium, Calcium, Titanium, Manganese
E	Oxygen, Silicon	----	Aluminum, Silicon, Sulfur, Iron
F	Oxygen, Iron	Silicon, Chlorine	Magnesium, Aluminum, Sulfur, Potassium, Calcium, Manganese
G	Chlorine	Iron, Oxygen	Aluminum, Silicon, Manganese
H	Oxygen, Iron	Silicon, Carbon, Aluminum, Phosphorous, Calcium	Sulfur, Chlorine, Sodium, Magnesium, Potassium, Manganese

This analysis shows that certain debris from the face and OD possesses elevated chlorine levels (Locations C, F, G), and in one instance (G), the debris is mostly chlorine. The location from which the debris labeled G was taken (see Appendix D) would face down in service. This is analogous to the 6 o'clock position. If water were to infiltrate the basement of 65 Main Street, Hopkinton, along the gas service line, any dripping of that water would occur by drops collecting at location G. Therefore, it is the most likely place for high-chloride residues and evaporates to collect.

Protocol Item 9: Leak Testing of Recovered Fitting

Leak testing of the recovered fitting was conducted since it was reasonably probable (see Fault Tree on Page 6) that a leak originated at this component. The fitting was recovered from the post-incident debris in two pieces, referred to in this report as MMR #11 (downstream piece) and MMR #18 (upstream piece). Leak testing was performed on the recovered fitting in two steps: 1) downstream portion of fitting and gas cock decoupled from the MMR #11 assembly; and 2) reassembled recovered transition fitting with gas cock (includes mating transition portion from MMR #18).

Leak Testing of Downstream End

Because the outer diameter of the downstream portion of the transition fitting (MMR #11) possessed a layer of very friable corrosion debris, plumbing directly to the fitting for this leak test would damage it severely and likely compromise the ability to evaluate the integrity of the fitting. Therefore, the upstream end of the downstream portion of the fitting was "potted" to a threaded pipe ring section with a clear epoxy used to make metallurgical mounts. Once hardened, this epoxy would act as a preservation device, preventing damage to the outer diameter of this fitting portion, and facilitating the leak test.

The first step in performing this preservative step was to affix the cleaned pipe ring to the cleaned surface of a common bathroom tile. This was accomplished with the use of dental impression compound.

Since the face of the fitting (MMR #11) had to be kept free of epoxy for proper alignment purposes later in the testing, the dental impression compound was applied to it as well, Figure 128. This compound would act to prevent epoxy from coating the fitting face, as well as act to hold the fitting/valve assembly in place on the tile during epoxy application. Then, once the tile was removed, the compound would easily separate from the fitting face with very minimal corrosion debris pick-up.

Once the impression compound was applied to the fitting face, the fitting/valve assembly was inverted onto the tile as shown in Figure 129. The dental impression compound was then allowed to cure completely, following package instructions. Clear Stycast epoxy was then poured around the fitting to a depth of approximately 0.54 inches. Air bubbles were then evacuated from the epoxy with the use of a vacuum chamber, Figure 130. This assembly was left undisturbed overnight to allow ample time for the epoxy to harden fully.

The next day, an attempt was made to remove the tile from the assembly (Figure 131) by lightly tapping the corners with a wooden block and scoring around the tile/epoxy interface with a thin x-acto knife blade. While the dental impression compound peeled away easily, the tile held fast. No mold release or other lubricating product could be used on this assembly during set-up, as it would have affected the ability of the dental impression compound to affix the metal ring and fitting/valve assembly into place for epoxy pouring. The tile would have to be removed by grinding. But first, since a ready-made seal was already in place, leak testing of the downstream portion of the fitting could proceed by plumbing the nitrogen supply to the downstream end of this assembly, Figure 132. No leakage was detected around the epoxy/fitting interface, the epoxy/ring interface, or the ring/epoxy/tile interface at an inlet pressure of 57 psi.

Two small leaks were detected on the valve portion of this assembly. Figures 133 and 134 show the leak between the valve stem and a hexagonal head portion of the valve. The second leak was located at the valve bottom, Figures 135 and 136. Neither leak was large enough to register on the in-line flow meter. This means the combined volume of both leaks was less than 2.37 ml/min, or 0.005 CFH. Once this leak test was complete, grinding removal of the tile could proceed, Figure 137. The tile was first ground with 60-grit paper, then finish ground with 120-grit paper. Grinding proceeded until the shadowy indication of the dental impression compound could be seen through the ceramic, Figures 138 and 139. A carpet knife was then used to pop through the remaining tile skin over the fitting orifice. This allowed a large piece of the tile to detach from the epoxy, Figure 140. The dental compound was then removed from the fitting face and saved, Figure 141. Dust-like pieces of tile debris on the fitting ID, left over from the break-through, were removed during a subsequent binocular microscope examination conducted expressly for that purpose.

Re-insertion of Recovered Fitting

Because of the delicate nature of reinserting the recovered fitting, the task was performed on the exemplar transition fitting first. Information provided by Inner-Tite Corporation indicated that the interior gasket is the only sealing member of this style fitting. From radiographic data and manufacturer drawings, it was noted that the end of the stiffener/tube assembly protruded beyond the interior rubber gasket toward the downstream end of the fitting. This protrusion, approximately 0.318-inches, conservatively, allowed chamfering of the black polymer gas line at the stiffener shoulder. Since the stiffener/tube assembly outer diameter is greater than the interior rubber gasket inner diameter when the interior gasket is in the energized (i.e. compressed) state, the two mating pieces of this type of transition fitting possess an interference fit once assembled. Also, the tube end at the stiffener shoulder flares a bit beyond the nominal tube OD. This is the result of the crimping action at the cupric ring. Both this flare and the interference fit can hamper reinsertion of such a fitting.

A chamfer on the tube end at the stiffener shoulder, however, leaves the stiffener intact, does not affect the sealing ability of the interior gasket (since it protrudes beyond it), and greatly facilitates reassembly of the two fitting pieces by eliminating the sharp 90° tube end that could catch on the ID of the interior rubber gasket.

To facilitate reinsertion of the exemplar transition fitting, the stiffener/tube assembly was marked at the 0.250-inch line from the stiffener shoulder and a chamfer tool was used to angle the tubing edge at the flare, Figure 142. The chamfer edge was smoothed with a light hand grind, Figure 143, to eliminate sharp tubing edges.

The exemplar pieces were then assembled by pushing the upstream and downstream pieces together using hand pressure. Figure 144 shows the inserted structure. Note that the cupric ring is fully in place. The inserted exemplar was then pulled apart so the conditions of the downstream side interior seal and the tubing could be examined. No adverse effects from the reinsertion were observed.

Based upon the results obtained with the exemplar, chamfering of the recovered fitting tubing at the stiffener shoulder proceeded so that reinsertion of the recovered fitting could be accomplished. To facilitate the chamfering, a mark was made at the 0.300-inch distance from the stiffener shoulder, Figure 145. This distance still allowed a margin of safety for the 0.318-inch distance of protrusion beyond the interior seal of the downstream side of the fitting.

The condition of the tubing of MMR #18 is shown in Figure 146. The tubing was chamfered with the same chamfering tool used on the exemplar, Figure 147. Since both the upstream and downstream ends of the recovered fitting possessed a light layer of powdery debris on the tubing and interior seal that would not have been present upon the initial assembly, these surfaces were cleaned with a swab and deionized water, Figure 148. The cleaned surface of the MMR #18 tubing is shown in Figure 149 and the interior seal of the downstream side (MMR #11) is shown in Figures 150 through 153. Due to the unevenness of the stiffener shoulder, the chamfer on the recovered fitting tubing (MMR #18), was uneven and possessed a steeper angle than did that on the exemplar. Figure 149 shows a discontinuity on the chamfer of this tubing resulting from the slightly warped stiffener shoulder.

At this point, an unsuccessful attempt was made to reinsert the recovered fitting. The steeper chamfer angle and greater interference between the interior seal on the downstream end (MMR #11) in the energized position and the upstream end tubing (MMR #18) combined to provide resistance to the reinsertion. While the resistance might have been overcome with force, it was decided that smoothing down the chamfer shoulder would provide a smoother reinsertion and greatly lower the chances of "catching" the interior seal on the tubing. The two portions of the recovered transition fitting were eased apart for this smoothing operation.

The interior seal of the downstream end (MMR #11) was again cleaned with deionized water and inspected for any damage caused by the aborted reinsertion attempt, Figures 154 and 155. Comparison of these two figures with Figures 151 and 153 shows that this seal was intact and exhibited no damage due to the reinsertion attempt.

The chamfered shoulder on MMR #18 was then manually ground on a polishing wheel with 240-grit paper. Care was taken not to heat the tubing material. Figure 156 shows the smoothed shoulder after cleaning with deionized water. This new configuration of the chamfer eliminated the sharp shoulder that could "catch" on the interior seal.

The interference between the upstream end tubing (MMR #18) and the downstream end interior seal (MMR #11) was another impediment to smooth reinsertion of the recovered fitting. A common way to assemble parts with interference fits is to make use of material expansion and contraction properties. Parts can be heated or chilled to facilitate assembly. Since heating assemblies that contain polymer parts is generally more likely to damage those polymer parts than chilling, chilling MMR #18 was investigated as a reinsertion aid.

An examination of technical data for the Phillips Driscopipe high molecular weight, high density PE3408 resin (included in Appendix I for your reference) indicates that this polyethylene material possesses a brittleness temperature below -180°F. This indicates that temperatures encountered in a typical modern household freezer will not damage the tubing. To check the amount of shrinkage that would be induced by a temperature soak in such a freezer, exemplar tubing from the same vintage as that recovered (but not from the recovered fitting) was placed in a household freezer after room temperature OD, ID, and wall thickness measurements were noted. Approximately two hours later, these measurements were repeated. The tubing was then left in the freezer overnight to check for further shrinkage. Measurements made the next morning revealed that the majority of the shrinkage occurred in the first two hours of the soak. Below are the average dimensional changes after two hours.

Table XI
Average Cold Soak Dimensional Changes, Exemplar Tubing

OD, inches	ID, inches	Wall Thickness, inches
-0.0056	+0.008	-0.003

This data indicates that the tubing OD and wall thickness shrank and that the tubing ID expanded. The OD shrinkage was the parameter that would reduce the interference between the tubing of MMR #18 and the interior seal of MMR #11.

Since a moisture film caused by condensate from the air could affect the sealing abilities of the reassembled fitting, MMR #18 was packaged in a clean plastic bag with an envelope of anhydrous calcium sulfate desiccant. The plastic bag was sealed with masking tape and placed in a freezer at a temperature of –3.3°F, Figure 157. Placement into the freezer occurred at approximately 8:45 a.m., and extraction occurred at 11:00 a.m. Freezer temperature at extraction was 1.5°F. The freezer was undisturbed during this cold soak duration.

After the two hour cold soak, MMR #18 was removed from the freezer, unbagged, and inserted into the downstream portion of the fitting using hand pressure and a smooth push/twist motion, Figures 158 through 160. Two pairs of light cotton gloves were worn under the standard latex gloves to minimize heat transfer during unbagging and insertion. The desiccant was checked for color to ensure the cold soak plastic bag remained dry, Figure 161. This desiccant changes color from blue to violet when saturated. As Figure 161 shows, the desiccant remained blue.

The reinserted fitting was then x-rayed at 0° and 90° to verify the placement of the stiffener shoulder and cupric ring. The results of this radiographic inspection indicated that the recovered transition fitting was fully reinserted, with the stiffener shoulder in contact with the integral ledge of the downstream portion of the fitting.

To ensure that the reinserted fitting was fully up to room temperature and that any condensation formed would not be a factor in subsequent testing, it was placed in a dry office environment with a bag of desiccant in contact under the fitting. This was left undisturbed for one calendar week.

Leak Testing of Re-inserted Fitting

Once this time period had elapsed, the reinserted fitting was plumbed for leak testing in the same bracket arrangement used for exemplar testing in Protocol Item 6, Figures 162 through 164. Pressure was applied gradually in 5 psi increments until 57 psi was reached. Indications on the in-line flow meter were noted at each pressure level. A small plumbing weep was detected at the inlet tygon tubing with leak detection fluid, Figure 165. This weep was repaired to the point where the flow meter indicator ball was "bottomed out" (i.e., registering no flow). The following table summarizes the leak test results of the reinserted recovered fitting.

Table XII
Leak Testing of Reinserted Fitting, Constrained, 0-50 CFH Flow Meter

Inlet Pressure, psi	Measured Flow, % Scale	Measured Flow, CFH
5	<0	<0
10	<0	<0
15	<0	<0
20	<0	<0
25	<0	<0
30	<0	<0
35	<0	<0
40	<0	<0
45	<0	<0
50	<0	<0
55	<0	<0
57	<0	<0

These results indicate that the reinserted fitting did not leak during the 27-minute duration constrained testing. While the pressure was at 57 psi, the bracket holding the fitting was loosened to allow the fitting approximately 5/8-inch of free longitudinal movement. This would allow the two pieces of the fitting some distance to "blow out", but would constrain this motion prior to an unsafe situation for test observers, Figure 166.

Because the chamfering operation served to reduce slightly the profile of the tubing face upon which the inlet pressure could act to produce a blow-out, the final portion of this leak testing involved raising the pressure to compensate for the reduction in profile area. An increase of 4.5 psi was required to compensate conservatively for this area loss. Therefore, the inlet pressure was first raised to 60 psi, then to 61.5 psi and the unconstrained assembly was allowed to rest for approximately twelve minutes. No flow registered on the flow meter. Table XIII below summarizes these results.

Table XIII
Leak Testing of Reinserted Fitting, Unconstrained, 0-50 CFH Flow Meter

Inlet Pressure, psi	Measured Flow, % Scale	Measured Flow, CFH
57	<0	<0
60	<0	<0
61.5	<0	<0

These results indicate that the reinserted fitting did not leak under unconstrained leak testing conditions.

Visual examination of the fitting after testing indicated that no movement apart of the upstream (MMR #18) and downstream (MMR #11) portions occurred during the above described unconstrained leak testing. To verify this observation, radiographic examination was once again performed at 0° and 90°, and the films were compared to those taken immediately after assembly.

Protocol Item 10: Analysis of O-ring Gasket

The downstream portion of the recovered transition fitting was sectioned from the gas cock to facilitate the examination of the gasket, Figures 167 through 170. Cutting was performed dry (i.e. without cutting fluid or other lubricant).

After sectioning, the gasket was examined for condition changes resulting from re-assembly and pull testing. This examination revealed that the gasket possessed the same appearance as prior to re-assembly and pressure testing. No cuts, abrasions, or other damage were imparted by the re-assembly and pressure testing.

To obtain a gasket segment for chemical analysis, the mounted portion of the downstream end of the recovered fitting (MMR #11) with approximately 120 degrees arc of gasket was chosen. This piece was examined after sectioning to obtain a metallurgical mount. A small amount of excess epoxy was removed and the gasket was gently pried from its position with a small spade screwdriver. The small spade screwdriver was chosen for this removal operation due to its flattened shape that could be inserted between the gasket and fitting body and not pierce the gasket during the extraction. Fiduciary marks were made on the gasket and body to mark the gasket's in-service position. Figures 171 through 174 shows the gasket extraction and marking.

The gasket from Exemplar A was also removed for analysis. To accomplish this, the four set screws were removed from the downstream end of the exemplar. This allowed the conical seat to be removed, exposing the gasket, Figure 175. Fiduciary marks were made on the gasket and its contacting parts and the gasket was extracted with gentle pressure from a small screwdriver. The gasket upstream side was marked with a "U" and the downstream side was marked with a "D". Figures 176 through 178 show these events.

For comparison purposes, a new gasket that had never been in service was also analyzed along with the gaskets from the recovered and exemplar fittings. Figures 179 through 181 show the gasket pieces analyzed.

The analyses consisted of dimensional inspection, hardness testing, and chemical analysis. The results of these analyses are summarized below.

Table XIV
Dimensional Inspection of Gaskets

Gasket	ID Unconstrained inches	OD Unconstrained inches	Wall thickness Unconstrained inches	Gasket Thickness (upstream to downstream) inches
MMR #11	----	----	0.26	0.345
Exemplar A	0.600	1.103	0.252	0.345
Inner-Tite DWG F-2009 Rev. M	0.590 ± 0.005	1.100 ± 0.005	----	0.350 +0.005 -0.003

The ID and OD measurements of the recovered fitting gasket in the unconstrained condition were unobtainable due to the sectioning involved in preparing a metallurgical mount. However, both the wall thickness and upstream-to-downstream gasket thickness measurements were consistent with the corresponding exemplar measurements. Also, calculating the resulting wall thickness from the nominal ID and OD measurements [(OD-ID) ÷ 2] yields a wall thickness of 0.255 inches. This value is consistent with both recovered fitting gasket and exemplar A gasket values.

Table XV
Hardness Testing of Gaskets

Hardness Shore A	Gasket				
	New	Exemplar A Upstream	Exemplar A Downstream	Recovered Upstream	Recovered Downstream
	56	53	55	55	60

Durometer hardness testing was performed on the new, unused gasket, and the upstream and downstream ends of both the exemplar and recovered gaskets. The results of this testing are summarized above. No durometer hardness values are specified on Inner-Tite drawing F-2009, Rev 01. The original test report is included in Appendix J for your information.

Table XVI
Summary of Chemical Analysis of Gaskets

Item Tested	Recovered Gasket	Exemplar A Gasket	New Gasket
Spectral Differences*	Increase of C = O	Increase of C = C	----
Tg, °C (°F)	-66 (-86.8)	-63 (-81.4)	-64 (-83.2)
% Processing oil	4	3	5
% Rubber	72	77	70
% Carbon Black	22	17	22
% Inorganic Residue	2	3	3

*Spectra compared to unused material.

Fourier transform infrared spectroscopy (FTIR) was used to identify the sample materials. The samples were prepared by the pyrolysis method. All three sample spectra are consistent with the reference spectrum for Polyisoprene, or rubber.

Differential scanning calorimetry (DSC) was used to determine each sample's glass transition temperature, or Tg and well below temperatures likely to be experienced in a basement. This is the temperature above which the polymer is soft and deformable and below which the polymer is glassy and brittle. The results of this analysis indicate that all three samples possess Tg's well below room temperature, indicating that they are deformable at room temperature and well below temperatures likely to be experienced in a basement. This is appropriate for a polymer intended to function as a gasket.

The Tg of the recovered gasket is somewhat lower than that of the new gasket, despite their similarities in composition. This could be indicative of some slight stiffening of the gasket material in service. This could, for example, be the result of a location near a furnace or other heat source. Such a stiffening is also consistent with long use, or aging.

Thermogravimetric analysis (TGA) was used to determine the composition of the three samples. The recovered gasket is very similar to the new, unused gasket. The gasket of Exemplar A, however, is different enough in composition to suggest a different formula or "recipe" was used to make the gasket. This is commonly the case in second-sources and different manufacturers, for example.

Overall, these results indicate that the rubber gaskets from the recovered fitting and from Exemplar A exhibit some characteristics of aging typically seen in older polymer parts. The compositional difference of the Exemplar A gasket are similar to those that might be found between different manufacturers of a similar product (i.e., a "second source"). The original reports and associated spectra are included in this report for your information in Appendix K.

Protocol Item #11: Metallurgical Examination of Downstream Portion of Fitting

The downstream portion of the recovered fitting (MMR #11) was mounted in clear epoxy to begin the process of creating a metallurgical cross section. This portion of the testing protocol was carried out in conjunction with Protocol Item #13: Metallurgical Examination of Upstream Portion of Fitting, to streamline the examination process, Figures 182 through 186. Ice water was used to cool the large mounts during epoxy curing as this curing is exothermic, Figure 186. The mounts were allowed to sit undisturbed for twenty-four hours at room temperature to allow for complete curing.

The completely solidified mounted fitting portions are shown in Figures 187, 188, and 189. Sectioning of a wedge-shaped piece from the 6 o'clock position of the downstream fitting portion is shown in Figure 190. This sectioning was also performed "dry". Figures 191 and 192 show the location of the wedge that was removed from the downstream portion of the fitting.

This wedge was then ground and polished to provide the smooth mirror-like finish required for metallurgical examination. Figures 193 and 194 show the downstream portion wedge before and after this grinding and polishing process.

The metallurgical mount was examined in both the as-polished and the etched conditions. Examination of a mount in the as-polished condition highlights objects such as inclusions, laps, etc., and conditions such as depth of corrosion penetration. Examination of a mount in the etched condition reveals material microstructure, microstructural changes associated with weld heat affected zones (HAZ), and any relationship corrosion may have with certain microstructural phases or features (i.e. preferential corrosion, grain boundary attack, etc.).

Figures 195 and 196 show the conical seat face of the downstream fitting portion (MMR #11). Recall that this was the region from which the EDS-analyzed debris was removed (Appendix D). These figures show a ferrite and pearlite microstructure with large inclusions, expected in the intended 12L15 material. A layer of general corrosion is present on the seat face, with maximum corrosion penetration of approximately 0.018 inch. The ferrite and pearlite microstructure and its ovoid inclusions are shown in Figure 197.

The junction between the seat and body is shown in Figures 198 and 199. Some general corrosion is present in this region as well. The presence of the interior gasket provides for sealing of the small gap between the seat and the body. Corrosion penetration from the seat OD in this region is approximately 0.026 inch, Figure 200.

Moving in a downstream direction, a shoulder of the body at the downstream outer diameter of the gasket is shown in Figures 201 and 202. Again, the microstructure is ferrite and pearlite with the inclusions expected in the intended 12L15 material. Higher magnification views of this region in the as-polished and the etched conditions are presented in Figures 203 and 204.

The weld region of the downstream portion of the recovered fitting is shown in Figures 205 through 207. A typical weld microstructural appearance was revealed by etching, Figures 206 and 207. The HAZ below the weld exhibits some grain growth that is typical of these regions, Figure 208. The microstructure of the body reverts to the original grain size and appearance very near to the small changes in the HAZ, Figure 209.

This metallurgical mount also revealed the fit-up between the gasket and the conical seat, Figure 210, and the gasket and the housing, Figure 211. These figures reveal a gasket in compression (note the slightly extruded lip in each figure) with a tight, gap-free fit between it and each adjacent metallic fitting part.

Overall, this examination revealed a well-compressed gasket with no gaps between it and its adjacent metallic fitting parts, a sound weld, and no through-wall corrosion penetration of either the conical seat or the body (housing). The material microstructure was consistent with the intended 12L15 alloy of the conical seat and body.

Protocol Item #12: Chemical Analysis of Downstream Fitting Portion Metal

The metallic components of the downstream portion of the recovered fitting were chemically analyzed to determine composition. Three parts in this sub-assembly required this type of analysis: the seat (Inner-Tite P/N F2002, AISI C12L15 steel), and the ¾ x 1-inch welded pipe nipple (Inner-Tite P/N 91692U, API 5L or ASTM A53). Figure 212 shows the location on the recovered fitting from which the first two samples were taken, and Figure 213 shows the location from which the third sample was taken.

Table XVII
Chemical Analysis Results – Downstream Fitting Portion

Element	Composition, %			
	Body	Seat	Welded Pipe	AISI C12L15
Carbon	0.086	0.074	0.15	0.09 maximum
Iron	Balance	Balance	Balance	Balance
Lead	0.27	0.25	<0.01	0.15 – 0.35
Manganese	1.01	1.02	0.45	0.75 – 1.05
Phosphorous	0.087	0.066	0.010	0.04 – 0.09
Sulfur	0.35	0.29	0.034	0.26 – 0.35

These results indicate that both the body and seat materials of the downstream fitting portion conform to the chemical requirements of AISI C12L15. These results also indicate that the welded pipe nipple material conforms to the chemical requirements of UNS G10120, G10150, and G10170, as well as the chemical requirements for all three types of pipe (Type S, Type E, and Type F) in ASTM A53-01, current for 2003. The original test reports are provided in Appendix L for your reference.

Protocol Item #13: Metallurgical Examination of Upstream Portion of Fitting

The upstream portion of the recovered fitting (MMR #18) was mounted in clear epoxy to facilitate creation of a metallurgical mount. This process was carried out in conjunction with Protocol Item #11, and a description of the process can be found in that section. Figures 182, 184, 185, 186 and 188 show the upstream fitting portion in the preparatory phase.

The fitting portion in completely solidified epoxy is shown in Figures 214 and 215. A wedge-shaped piece was sectioned from this mounted portion with a dry saw, Figure 216. As with the downstream portion examined in Protocol Item #11, the wedge from the upstream portion was cut from the 6 o'clock position. Figure 217 shows the location of this wedge.

This wedge was then ground and polished to provide the smooth, mirror-like finish require for metallurgical examination. Figures 218 and 219 show the upstream portion wedge before and after this grinding and polishing process.

The metallurgical mount was examined in both the as-polished and the etched conditions. Figures 220 and 221 show the downstream end of MMR #18, at the cupric groove ring. The microstructure of the bushing is ferrite and pearlite with the inclusions expected in a free-machining steel. This microstructure is consistent with the intended C12L15 alloy. Maximum corrosion penetration into the bushing nose: the depth of this penetration is approximately 0.03 inch. Directly at the bushing nose the maximum corrosion penetration is approximately 0.007 inch, Figure 122. The bushing microstructure, the cupric groove ring, and the corrosion layer between them is visible at higher magnification in Figure 223.

When properly assembled, the upstream and downstream portions of the fitting are threaded together. The two pieces of the recovered fitting examined in this investigation were submitted to MMR in a separated condition. The upstream portion of the recovered fitting, MMR #18, retains traces of the threads of the downstream portion (MMR #11), in a position that indicates the two pieces were formerly threaded together, Figures 224 through 231. This is consistent with the interior gasket being in the compressed condition and the flattened and cracked condition of the cupric groove ring.

An overall view of the downstream-most OD threads on MMR #18 is shown in Figures 224 and 225. In this location, only traces of the mating threads from the downstream portion of the recovered fitting (MMR #11) remain, Figures 226 and 227. Corrosion has also consumed the remaining threads.

The upstream-most portion of the OD threads on MMR #18 is shown in Figures 228 and 229. The remains of a mating thread from MMR #11 in this region are shown in Figures 230 and 231. Note that the microstructures of MMR #18 and the thread remnant of MMR #11 are the same. This is consistent with the results of the chemical analyses performed on their respective constituent materials.

MMR #18 also possessed internal thread remnants on this upstream ID, Figures 232 and 233. These remnants indicate that the foundation sleeve, MMR #12, was once threaded to the upstream ID of MMR #18. Examination of the mating thread interface in this region, Figure 234 revealed that the bushing of MMR #18 and the foundation sleeve were very likely different materials, based upon inclusion content. Etching revealed different microstructures, Figures 235 and 236, confirming the differences. Since galvanic corrosion is a possibility whenever two dissimilar metals contact each other in a moist environment, chemical analysis of MMR #12 was necessary to reveal the alloy from which this foundation sleeve was made.

Overall, this examination revealed a bushing microstructure consistent with the intended 12L15 alloy, moderately severe corrosion penetration of the bushing material near the cupric groove ring, and corroded remnant mating threads of a material consistent with that of the downstream portion of the recovered fitting (MMR #11). This examination also revealed that the material of MMR #12, the foundation sleeve, was different from the MMR #18 bushing material. This finding indicated the need for chemical analysis of the foundation sleeve material

Protocol Item #14: Chemical Analysis of Upstream Fitting Portion Metal

The metallic portion of the upstream side of the recovered fitting was chemically analyzed to determine its composition. Per Inner-Tite drawing F-2104m the bushing portion of the upstream side of the fitting is intended to be C12L15 steel. The corrosion on the surface of this part was ground away to expose bright metal for the analysis. The results of this analysis are summarized below.

Table XVIII
Chemical Analysis Results – Upstream Fitting Bushing

Element	Composition %	
	Recovered Bushing	AISI C12L15
Carbon	0.069	0.09 maximum
Iron	Balance	Balance
Lead	0.20	0.15 – 0.35
Manganese	0.98	0.75 – 1.05
Phosphorous	0.055	0.04 – 0.09
Sulfur	0.32	0.26 – 0.35

These results indicate that the bushing material conforms to the chemical requirements of AISI C12L15. The original test report is included in this report in Appendix M for your reference.

Protocol Item 15: Microscope Examination of Fractured Pipe Ends

Fractured pipe ends were present on nearly every piece of recovered jurisdictional piping received by MMR for investigation. Examination of fine fractographic features of several of these fractures was necessary to determine whether or not they indicated fracture as a result of the incident, or as a result of pre-existing metallurgical conditions. To perform this examination, all fractures were sectioned from their piping and related equipment, Figure 237. The sectioning was performed with dry, unlubricated cutting tools to avoid cutting fluid contamination of deposits on and near the fracture surfaces. The cut fractures and their descriptions are summarized below.

Table XIX
Sectioned Fracture Descriptions and Origins

MMR ID	Envelope Description	Origin
6	Inlet valve, male end	Meter #5070 inlet
7	Outlet fractured male thd. end	Meter #0965 outlet
8	Inlet valve, female end	Meter #21571 inlet
8	Gooseneck end	Meter #21571 outlet
9	Male thd. end	1" gas pipe with tee
10	1" Tee end	1" gas pipe with tee and swivel nut
10	Male thd. end	1" gas pipe with tee and swivel nut
11	Outlet of meter S/N W005220 fractured end	Meter #5220 outlet
11	Regulator relief pipe fractured end	Downstream end of regulator relief pipe
11	Outlet of meter S/N Q004231 fractured end	Meter #4231 outlet
14	Male thd. end	Upstream end of regulator relief pipe

These fractures, plus that located on MMR #15 (not sectioned) were examined with a binocular microscope at magnifications up to 50X. Fracture origin regions, or the regions in which these fractures began, were located. Deposits on and near the fracture surfaces were also noted. Based upon this examination, five fractures were selected for further examination in a scanning electron microscope (SEM). The fractures were MMR #6, MMR #9, MMR #10 (male thd. end), MMR #11 (Meter #4231 outlet), and MMR #11 (regulator relief pipe).

Scanning Electron Microscope Examination

A view of the fracture surface of MMR #6 is shown in Figure 238. A number of regions of colored debris can be seen on this fracture surface. Various regions of this debris were analyzed with a qualitative microchemical analysis technique known as energy dispersive x-ray spectroscopy, or EDS. This analysis technique uses equipment attached to the SEM to reveal the elements present in the analyzed region. The output spectrograms contain peaks of various heights that correspond to the relative amounts of the elements present. The results of these analyses on MMR #6 are summarized below.

Table XX
EDS Results – MMR #6 Fracture Surface

Debris Description	Elements Present		
	Major	Minor	Trace
White Debris on Fracture Surface	Calcium	Aluminum, Silicon, Lead	Sodium, Magnesium, Chlorine, Potassium, Copper
Blue/Green Debris on Fracture Surface	Calcium	Magnesium, Aluminum, Silicon, Lead, Copper	Phosphorous, Chlorine, Iron
Green Debris on Thread	Silicon	Magnesium, Calcium	Sodium, Aluminum, Sulfur, Chlorine, Potassium, Titanium, Iron, Copper
Blue/White Debris on Fracture Surface	Lead	Chlorine, Calcium, Copper	----
Grey Debris on Fracture Surface	Silicon	Aluminum, Magnesium, Iron	Sulfur, Chlorine, Potassium, Calcium, Copper
Brown Debris on Thread	Sulfur, Calcium	Silicon	Magnesium, Aluminum, Titanium, Iron, Copper

These results are consistent with elements typically found in common dirt (silicon), and cement (calcium), or pipe thread compound. Both of these elements can also be found in insulations. The lead could be a component of piping solder if a soldered joint nearby the fracture were damaged enough to deposit powdery debris, or of paint that was exposed during the incident. The original spectrograms are included for your reference in Appendix N.

After EDS analysis, the fracture was cleaned ultrasonically in acetone. This type of cleaning serves to remove loosely adhered debris and oily residues from a fracture, without affecting the metallic portions of the fracture.

A view of the fracture origin region is provided in Figure 239. At approximately mid-wall, features known as ductile dimples are present, Figures 240 and 241. These are indicative of an overload fracture that pulled the piping apart. These features are also present at the thread root where the fracture originated, Figures 242 and 243, despite the dendritic appearance of this region under the binocular microscope. Dendrites are casting features formed during cooling of the casting melt. If they present a smooth, unmarred, convex appearance, they indicate casting porosity. That is not the case here. The dimples follow the dendrite matrix, but indicate that the metal was fused at a point in the past and separated under the force that caused the fracture. These dimple features were present over the whole of the fracture surface. This type of fracture feature is consistent with damage incurred during the incident under the single application of a force that exceeded the capability of the material. No features were observed that would indicate material defects.

A view of the fracture surface of MMR #9 is shown in Figure 244. As with MMR #6, various regions of debris were analyzed with EDS. The results of these analyses are summarized below.

Table XXI
EDS Results – MMR #9 Fracture Surface

Debris Description	Elements Present		
	Major	Minor	Trace
Debris in Split*	Iron, Oxygen	----	Silicon, Sulfur, Chlorine, Calcium, Carbon
Fracture Surface** Debris Near Split	Iron	Chlorine	Aluminum, Silicon, Phosphorous, Sulfur, Calcium

*Analyzed in Standard Mode and Light Element Mode
** After Cleaning in Acetone

The debris on this fracture surface is consistent with iron oxide, or common rust. Analysis of the debris in the split was performed in both Standard Mode and Light Element Mode. Light Element Mode is more sensitive to elements with lower atomic weights (i.e. oxygen, carbon, etc.). It was utilized in this case in addition to Standard Mode because the split referred to followed the pipe seam Figure 245. The possibility of a manufacturing defect in such a case was therefore considered.

The EDS analyses of debris on the fracture surface near the split was performed subsequent to an ultrasonic acetone cleaning. The cleaning appears to have had only a minor effect, if any, on the elements detected. The original spectrograms are included for your reference in Appendix O.

The ultrasonic cleaning in acetone allowed scattered regions of fracture features to become visible through the layer of iron oxide on the fracture. However, not enough features were revealed for a complete examination of the fracture surface. Since the corrosion debris appeared light-colored and possessed a fresh appearance, a short time (20 seconds) ultrasonic cleaning in a light solution of oxide remover was performed. This had the effect of removing the majority of the oxide coating and revealing the fracture features. Figure 246 shows this fracture surface after cleaning.

The fracture origin region of this fracture is shown in Figures 247 and 248. Large regions of cleavage are interspersed among the dimple rupture features. These cleavage facets are typically associated with shock-style fractures that are the result of suddenly-applied loads. Because most of the fracture surface consists of ductile dimple features, with clusters of cleavage at the fracture origin region, Figures 249 through 251, the sudden loading that caused the cleavage could have preceded the loading that caused the dimple rupture, or could have abated enough to produce the dimple features.

The fracture surface in the vicinity of the final fracture (the last part of the material to separate) is shown in Figures 252 and 253. The shear dimples coincide with thread damage, indicating a tearing apart of the piping at that region.

The split at the pipe seam is shown in Figures 254 and 255. The fracture features on the fracture surface adjacent to the split are ductile dimples, Figures 256. The fracture features on the split face are also ductile dimples, Figure 257.

Overall, the fracture features present on MMR #9 are consistent with a sudden loading that produced some regions of cleavage, followed by a more gradual loading application that produced ductile and shear dimples and split the pipe seam. The ease of removal of the oxide on the pipe seam face indicates light corrosion, more typical of a fresh ferrous (iron-based) fracture in a moist environment than of a long-standing defect. The presence of fracture features on the split face indicate that the metal of the split was fused at one point and the region was not a piping manufacturing defect. This piece possesses fracture features consistent with being caused by the incident. No features were observed that would indicate material defects.

A view of the fracture surface of MMR #10 "Male Threaded End", is shown in Figure 258. As with the previously discussed fractures, various regions of debris were analyzed with EDS. The results of these analyses are summarized below.

Table XXII
EDS Results – MMR #10, Male Threaded End Fracture Surface

Debris Description	Elements Present		
	Major	Minor	Trace
Origin Region Debris	Sulfur	Chlorine, Calcium, Iron	Sodium, Magnesium, Aluminum, Phosphorous, Potassium, Silicon, Titanium, Zinc
Dark Grey Deposit	Sulfur	Silicon, Chlorine, Calcium, Iron	Sodium, Magnesium, Aluminum, Phosphorous, Potassium, Titanium, Manganese, Copper, Zinc

The sulfurous component of the debris on this fracture surface is consistent with the use of the sulfur-based compound mercaptan in natural gas. Chlorine was found in corrosion debris on other examined pieces. It could have its source in water infiltrating the basement, water from applied water (fire department), or it could have come from common insulation. Calcium is a component of cement and many rocks. Silicon is a common sand element. The pipe piece examined was a ferrous alloy, explaining the iron. The original spectrograms are appended to this report for your reference in Appendix P.

After an ultrasonic cleaning in acetone, the fracture features on this specimen were clearly revealed. Figures 259 through 261 show the ductile dimple fracture morphology present at the fracture origin of this piece. Examination of the rest of the fracture surface revealed the same ductile dimples over the entire fracture surface. This type of fracture surface is consistent with being caused by the incident. No features were observed that would indicate material defects.

A view of the fracture surface of MMR #11, Meter #4231 outlet (referred to as MMR #11, 4231) is shown in Figure 262. The EDS analysis results of the debris present on the fracture surface are summarized below. Figure 263 shows the two regions referred to as Area 1 and Area 2.

Table XXIII
EDS Results – MMR #11, 4231 Fracture Surface

Debris Description	Elements Present		
	Major	Minor	Trace
Clean-appearing region	Iron	----	Sodium, Magnesium, Silicon, Phosphorous, Sulfur, Chlorine, Calcium, Manganese, Zinc
Dark grey debris near ID	Iron	Sodium, Silicon, Sulfur, Calcium, Zinc, Lead	Magnesium, Aluminum, Phosphorous, Chlorine, Potassium, Barium, Manganese
Dark grey debris near ID, 2nd reg.	Lead, Carbon	Silicon, Calcium, Iron, Oxygen	Sodium, Magnesium, Aluminum, Chlorine, Potassium, Titanium, Copper, Zinc
Debris in Area 1	Iron	Calcium	Sodium, Magnesium, Aluminum, Silicon, Phosphorous, Sulfur, Chlorine, Manganese, Zinc
Debris in Area 2	Iron	Magnesium, Silicon, Calcium, Sulfur	Sodium, Aluminum, Phosphorous, Chlorine, Manganese, Zinc
White debris near OD	Lead	----	Manganese, Iron
ID coating	Zinc, Lead	----	Silicon, Calcium, Iron

These results, along with the EDS results of the ID coating, indicate that coating debris and iron-based compounds make up the constituents of the debris found on this fracture surface. The original spectrograms are appended to this report for your reference in Appendix Q.

After an ultrasonic cleaning in acetone, the fracture surface of this specimen was examined. The fracture origin region is shown in Figure 264. A small region of interdendritic fracture was present near the thread root, Figures 265 and 266. This region was small compared to the predominant ductile dimple fracture mode present over the rest of the fracture surface at the origin region, Figures 267 and 268.

Overall, the fracture surface consisted of ductile dimple features occasionally interspersed with small regions of interdendritic fracture at the general origin and final fracture regions. The largest region of interdendritic fracture was seen at the final fracture region, Figures 269 through 271. Interdendritic regions such as these are expected and typically seen on the fracture surfaces of cast products. The location of the interdendritic regions near the fracture origin are inboard of the thread root and therefore separated only after the thread root meal had fractured. The fracture features seen on this specimen are consistent with having been caused by the event. No features were observed that would indicate material defects.

A view of the fracture surface of MMR #11, "Regulator Relief Pipe" (referred to as MMR #11, R.R.P.) is shown in Figure 272. The EDS results of the debris analysis are summarized below.

Table XXIV
EDS Results – MMR #11, Regulator Relief Pipe Fracture Surface

Debris Description	Elements Present		
	Major	Minor	Trace
Thread deposit near origin	Iron	Silicon, Sulfur, Calcium, Zinc	Aluminum, Chlorine
Fracture surface deposit near origin	Silicon, Calcium	Sulfur, Iron	Sodium, Magnesium, Aluminum, Phosphorous, Chlorine, Potassium, Titanium, Chromium, Zinc
Fracture surface deposit 90° CCW from origin	Silicon, Calcium	Aluminum, Sulfur, Iron, Sodium, Chlorine, Potassium	Magnesium, Phosphorous, Titanium, Zinc
Fracture surface deposit near final fracture	Calcium	Sulfur, Silicon	Sodium, Magnesium, Aluminum, Phosphorous, Chlorine, Potassium, Titanium, Chromium, Iron, Zinc

The debris present on the fracture surface and thread near the fracture surface is consistent with elements typically found in common sand, cement, and a scent compound used in natural gas, as well as thread compound. The original spectrograms are appended to this report for your reference in Appendix R.

After ultrasonic cleaning in acetone, the fracture origin region revealed ductile dimple morphology, Figures 273 through 275. This fracture mode was consistent over the entire fracture surface. Figures 276 and 277 of the final fracture region illustrate this. As with all other fracture surfaces examined in this manner, this fracture is consistent with having been caused by the incident. No features were observed that would indicate material defects.

Protocol Item #16: Metallurgical Examination Fractured Pipe Ends

A decision was made not to perform the testing described in this Protocol Item since no fracture surface evidence suggested any metallurgical defects. Further, this preserves the condition of the pipe end fractures.

Protocol Item #17: Chemical Analysis of Fractured Pipe Ends

Due to the results of the metallurgical examination of the upstream portion of the recovered fitting (MMR #18), a chemical analysis of the foundation sleeve material (MMR #12) became necessary. The results of this analysis are summarized below.

Table XXV
Chemical Analysis Results – Foundation Sleeve (MMR #12)

Element	Composition	
	Foundation Sleeve (MMR #12)	Typical Modern Low Carbon Steel
Carbon	0.078	0.03 – 0.12
Copper	<0.01	----
Iron	Balance	Balance
Manganese	0.50	0.20 – 0.60
Phosphorous	0.07	0.04 maximum
Silicon	0.01	0.02 – 0.15
Sulfur	0.050	0.04 maximum

These results are similar to the typical compositions found in modern low carbon steel. The composition of the foundation sleeve meets no modern specifications due to the slightly higher phosphorous content. However, the material is similar to 1008. The original test report is included in Appendix S for your reference.

Since the foundation sleeve experienced heavy corrosion at its downstream end, an investigation into possible corrosion acceleration due to aggressive chemical spices was investigated. Corrosion debris was collected from the downstream end of the foundation sleeve for this analysis, Figure 278. Debris was collected from 12 o'clock, 3 o'clock, 6 o'clock, and 9 o'clock positions of the downstream end. These positions are those clock positions viewed when looking longitudinally upstream of MMR #12 (i.e. the downstream end closets to you). Debris from the OD and the 6 o'clock position of the ID of the end ring sectioned for chemical analysis was also taken.

This debris and the end ring section can be seen in Figures 279 through 282. Analysis of this debris was accomplished using energy dispersive x-ray spectroscopy, or EDS in the standard mode, except where the light element mode is indicated. This analysis technique is explained in earlier sections. The results of this analysis are summarized below.

Table XXVI
EDS Results – Foundation Sleeve (MMR #12) Debris

Position	Debris Description	Elements Present		
		Major	Minor	Trace
12 o'clock	Red	Iron	Calcium	Aluminum
	Orange	Iron	Calcium	Magnesium, Aluminum, Silicon, Manganese
	White	Silicon	Aluminum, Calcium	Magnesium, Potassium, Manganese, Iron
	Grey	Iron	Calcium	Magnesium, Aluminum, Silicon, Phosphorous, Chlorine, Manganese
3 o'clock	Black	Iron	----	Magnesium, Aluminum, Silicon, Potassium, Calcium
	Glassy Red	Iron	Calcium	Magnesium, Aluminum, Manganese
	Orange	Iron	Calcium	Magnesium, Aluminum, Silicon, Sulfur, Potassium, Manganese
6 o'clock	White	Iron	Calcium	Magnesium, Aluminum, Silicon, Manganese
	Green*	Iron, Oxygen	----	Magnesium, Aluminum, Silicon, Calcium, Manganese
	Dark Red	Iron	----	Magnesium, Aluminum, Calcium
	Silver	Iron	----	Aluminum, Calcium
	White (2nd region)*	Calcium, Oxygen	Carbon	Aluminum, Silicon, Phosphorous, Iron
9 o'clock	Yellow	Calcium	----	Aluminum, Silicon, Phosphorous, Iron
	Orange	Iron, Oxygen	Calcium	Carbon, Sodium, Magnesium, Aluminum, Silicon, Phosphorous, Manganese, Iron
	White	Calcium	----	Magnesium, Aluminum, Silicon, Phosphorous, Sulfur, Iron
9 o'clock debris (overall)*		Calcium, Oxygen	Carbon, Iron	Sodium, Magnesium, Aluminum, Silicon, Phosphorous, Sulfur, Potassium
End Ring Debris (ID 6 o'clock position)*		Iron, Oxygen	Carbon	Aluminum, Silicon Sulfur, Calcium, Iron
End Ring Debris (OD)*		Silicon, Oxygen	Aluminum	Carbon, Sodium, Magnesium, Phosphorous, Potassium, Calcium, Titanium, Iron

*Analyzed using Standard Mode and Light Element Mode.

In general, the spectra of the various colors of debris are consistent with oxides of iron, or common rust, in conjunction with calcium. Calcium is commonly found in cement. Some debris is predominantly silicon, aluminum, and oxygen. These elements are commonly found in sand and soil. The OD End Ring Debris consisted of a brownish-grey sand substance consistent with common dirt. No aggressive elements were found in this debris. No chlorine was found in any of the debris from MMR #12, except for one instance of a trace amount in the grey debris from the 12 o'clock position. This level of chlorine could have been caused by human handling prior to receipt of the part by MMR. The trace amount seen here is consistent with a human handling source.

Note that only certain debris was analyzed with Light Element Mode. In the interest of expediency, spectra similarities were considered, and an example of debris with each type of spectrum was analyzed using Light Element Mode. The original spectrograms are appended to this report for your reference in Appendix T.

To summarize the foundation sleeve evaluation, the sleeve material is a low carbon steel. The transition fitting material to which it is mated is also a carbon steel. The differences in these two materials is not significant enough to cause galvanic corrosion. Further, the environment that caused the corrosion does not contain appreciable aggressive species, indicating corrosion by moisture alone.

SUMMARY

To summarize the results of all the testing performed in this investigation, it is helpful to refer back to the fault tree originally used to develop the test and evaluation protocol. This fault tree indicates the need to test the components of the jurisdictional piping for reasonably probable leak sources. The following table isolates these components as the items tested, lists the testing performed, and summarizes the results of that testing.

Table XXVII
Testing Results Summary

Item(s) Tested	Testing Performed	Testing Results
Meters	Visual examination	Cracking consistent with explosion and house collapse
	Radiographic Inspection	No anomalies
	Leak Testing	No leakage
Piping Joints Downstream of Regulator	Visual Examination	Some fractures at joints consistent with incident damage. No evidence of breaches at intact joints. Riser pipe union pipes at an angle not straight.
	Radiographic Inspection	No anomalies, no cross-threading, acceptable thread penetration
	Leak Testing	Low-flow weepage leaks consistent with incident damage.
Piping Lengths Downstream of Regulator	Visual Examination	No breaches
	Leak Testing	No leaks (no pressure drop in static pressure test)
Regulator	Visual Examination	No breaches or joint anomalies
	Radiographic Inspection	No anomalies
	Leak Testing	No leaks
	Functional Test	Regulates downstream pressure properly; vents at indicated trip pressure
Regulator Vent Pipe	Visual Examination	No breaches, fracture at 90° elbow near house sill.
	Radiographic Inspection	No anomalies, no cross-threading, acceptable thread penetration.
	Leak Testing/Flow Testing	No leaks, no blockages.
Upstream Portion of Transition Fitting	Visual Examination	Corrosion on ferrous portions, no blockages, out of round stiffener shoulder, gouge in tubing at stiffener.
	Radiographic Inspection	Acceptable thread penetration, no cross-threading.
	Flow Testing	No blockages
	Microscopic Examination	Cupric ring cracked circumferentially; layered, friable corrosion debris on ferrous portion; evidence of contact with downstream fitting portion, chlorine present in corrosion debris in generally trace amounts. Material microstructures normal. Evidence of acceptable thread penetration for formerly threaded together parts. Fitting wall shows no breaches or leak paths. Foundation sleeve a different material than body.

Table XXVII (continued)
Testing Results Summary

Item(s) Tested	Testing Performed	Testing Results
Downstream Portion of Transition Fitting	Visual Examination	Valve in "open" position, corrosion present on ferrous fitting parts, inside seal intact and in place.
	Radiographic Inspection	Possible lack of fusion in weld joint that was not open to surface. No other anomalies.
	Microscopic Examination	Corrosion on ferrous parts, no blockage of valve visible, axial rub marks on gasket ID and circumferential ripples at downstream end, indications of contact with upstream fitting part, high chlorine content of face corrosion debris. Material microstructures normal. Weld structure normal with no leak path. Fitting wall shows no breaches or leak paths. Gasket in compressed position.
	Leak Testing	Weepage at stem nut and bottom of valve. No leakage in transition fitting, including weld.
Reassembled Recovered Fitting	Radiographic Inspection	Assembly complete, stiffener shoulder bottomed out on integral ledge. No evidence of "walking" or of fitting pulling apart due to leak testing.
	Leak Testing	No flow on flow meter, no fitting leaks. No movement of fitting when restraint removed.
Piping Joints Upstream of Regulator	Visual Examination	No anomalies.
	Radiographic Inspection	Acceptable thread penetration, no cross-threading
	Leak testing	No leaks
Piping Lengths Upstream of Regulator	Visual Examination	No breaches
	Leak Testing	No leaks (no drop in pressure in static pressure test)

CONCLUSIONS

- The jurisdictional piping and appurtenances received by MMR for this investigation exhibited no blockages.

- The jurisdictional regulator functioned as intended and in a manner consistent with its labeling.

- Leak testing revealed only very low flow leaks in the jurisdictional piping, including the transition fitting. These leaks are consistent with leaks caused by damage sustained as a result of the incident, and are not causes of the incident.

- Energy dispersive x-ray spectroscopy (EDS) analysis on corrosion debris from the recovered transition fitting revealed that the major elemental constituents were iron and oxygen. Oxides of iron are the major constituents of common rust. The presence of various amounts of chlorine, which is known to be aggressive to ferrous (iron-based) materials, were detected. In one location, corresponding to the as-installed, in-service 6 o'clock position, this element was present in major amounts. Any chlorine-containing compounds carried onto the transition fitting by water entering the basement would collect at this 6 o'clock position, concentrating as the water evaporated. All other instances of chlorine detection indicated minor to trace amounts, or levels that would be consistent with human handling with ungloved hands prior to arrival at MMR.

- Chemical analysis of the recovered transition fitting materials indicated that those materials were as specified by Inner-Tite Corporation on drawings and bills-of-materials.

- Overall, both the upstream and downstream portions of the recovered transition fitting possessed a rather heavy layer of friable corrosion. EDS analysis indicated that this was predominantly iron and oxygen, consistent with common rust. The fitting was delivered to MMR in two pieces. The male threads of the upstream portion (MMR #18) possessed traces of the downstream portion (section of MMR #11) female threads, indicating a loss of mechanical retention between the two pieces. Metallurgical evaluation revealed a large percentage of wall thickness remaining on both upstream and downstream ends of the recovered transiting fitting. No breaches in the walls were revealed. X-ray radiographic data supports this finding. The rubber gasket present in the downstream end was in the compressed position. This position is the proper one for maintaining the gas-tight seal within the transition fitting.

- Pull-out testing (a non-protocol item) was performed twice: once on the plastic hose of the modified exemplar, and once on the plastic hose of the recovered fitting after leak testing was complete. In the first instance, a force of 85 lb was required to pull out the hose. In the second case, a force of 84 lb was required to pull out the hose. These results are consistent with each other.

- Scanning electron microscope (SEM) examination of fractured pipe ends revealed that the majority of the fracture features were ductile dimple rupture, indicating fracture by the single application of a force that exceeded the capability of the material. A small amount of cleavage fracture features were present on some fracture surfaces. This is consistent with a small amount of damage being caused by the explosion (cleavage fracture) followed by overloading of the piping system by the house collapse (dimple rupture fracture).

- Leak testing of the fully reinserted recovered transition fitting revealed no leakage in the fitting; the only leak detected was at the gas cock. This leakage was of very low volume (i.e. did not register on the flow meter where the first marked gradation is equivalent to 0.58 CFH) and is likely the result of the incident.

  During this leak testing, the fully reinserted fitting did not "walk" or move apart as a result of gas line pressure. X-ray radiographic inspection after leak testing confirmed that the internal components did not move apart. This indicates that the 57 psi gas line service pressure was not enough to move the two halves of the fully reinserted fitting apart, even when ample space to do so was available.

  Typically, piping systems provide both upstream and downstream resistance against such movement of their components. The weight of the piping and its related components acts against movement, as do the clamps and braces that affix the system to the house. This testing indicates that the recovered transition fitting could not come apart, or move sufficiently on its own from a fully reinserted position, to cause leakage. This indicates that the fitting came apart as the result of either 1) the explosion and/or subsequent collapse of the house located at 65 Main Street, Hopkinton, Massachusetts, or, 2) the application of an unknown external force or forces (not necessarily directly applied to the jurisdictional piping) prior to the event.

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

June 15, 1972

D.P.U. 11725-F

MASSACHUSETTS GAS DISTRIBUTION CODE

ORDERED: Pursuant to sections 66, 76 and 105A of Chapter 164 of the General Laws as amended, and after due notice and hearing, the Department of Public Utilities (D.P.U.) hereby adopts rules to insure safe operating practices of gas corporations and municipalities subject to said Chapter 164 engaged in the distribution of gas.

Every gas corporation and municipal gas department engaged in the distribution of gas within the Commonwealth of Massachusetts shall be governed by the rules hereinafter enumerated. Such rules shall apply to all new construction and new installations made subsequent to the effective date of these regulations and shall not apply retroactively to existing installations.

Section 1

1. Compliance with MFS Standards

Every gas piping system shall be constructed, operated and maintained except as otherwise provided in this regulation, in compliance with the provisions of: Part 192 in Title 49, Code of Federal Regulations, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards published August 19, 1970 including the following amendments: 192-1 published October 21, 1970, 192-2 published November 11, 1970, 192-3 published November 17, 1970, 192-4 published June 30, 1971, 192-5 published September 10, 1971, and 192-6 published December 31, 1971 red to herein as the MFS Standards). Subsequent amendments, additions revisions to the MFS Standards shall be reviewed by the Department. anges of technical import which would affect the operation of gas distri- tion companies in Massachusetts shall be considered at a public hearing thin sixty days of the date of issuance. The D.P.U. will maintain a ference file containing the aforementioned federal regulations and in- rporated documents.

2. <u>Applications for Exceptions and Waivers from Provisions of e D.P.U. Regulations</u>.

(a) A gas corporation or municipal gas department may make a written request to the D.P.U. for an exception to the provisions of paragraphs 4, 5, and 6 of Section 1 of this regulation. The D.P.U. may, after consideration, and the payment of the appropriate fee, issue exception requested or modifications thereof to the particular gas corporation or municipality requesting such exception. In emergencies, a verbal exception may be granted by the D.P.U. which will then be confirmed by written request within seven days.

(b) The D.P.U. may issue a waiver to a gas corporation or municipal gas department from the provisions of Part 192 in Title 49 of the Federal Regulations providing that the waiver pertains to an intrastate facility and the D.P.U. gives notice of such waivers to the Department of Trans- portation at least 60 days before the waiver becomes effective.

3. Listing of Definitions Contained in Part 192 (Subpart A Section 192.3) of the MFS Standards.

As used in this part:

Distribution Line means a pipeline other than a gathering or transmission line.

Gas" means natural gas, flammable gas, or gas which is toxic or corrosive.

"Gathering line" means a pipeline that transports gas from a current production facility to a transmission line or main.

High pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer. (See Par. 6 of this regulation).

Listed specification means a specification listed in Section I of Appendix B of this part.

Low pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer. (See Par. 6 of this regulation).

Main means a distribution line that serves as a common source of supply for more than one service line.

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of one year.

Maximum allowable operating pressure means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Municipality means a city, county or any other political subdivision of a State.

"Operator" means a person who engages in the transportation of gas.

"Person" means any individual, firm, joint venture, partnership, [...]poration, association, State, municipality, cooperative association, [...] joint stock association, and includes any trustee, receiver, assignee, [...] personal representative thereof.

"Pipe" means any pipe or tubing used in the transportation of gas, [...]cluding pipe-type holders.

"Pipeline" means all parts of those physical facilities through [...]ich gas moves in transportation, including pipe, valves, and other [...]purtenances attached to pipe, compressor units, metering stations, [...]gulator stations, delivery stations, holders and fabricated assemblies

"Pipeline facility" means new and existing pipelines, rights of [...]nd any equipment facility, or building used in the transportation [...] gas or in the treatment of gas during the course of transportation.

"Secretary" means the Secretary of Transportation or any person [...] whom he has delegated authority in the matter concerned.

"Service Line" means a distribution line that transports gas to [...]customer meter set assembly from a common source of supply.

"SMYS" (specified minimum yield strength) is:

(1) for steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification, or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with 192.107(b).

State" means each of the several states, the District of Columbia and the Commonwealth of Puerto Rico.

"Transmission line" means a pipeline, other than a gathering line that:

(1) Transports gas from a gathering line or storage facility to a distribution center or storage facility;

(2) Operates at a hoop stress of 20 per cent or more of SMYS, or,

(3) Transports gas within a storage field.

"Transportation of gas" means the gathering, transmission, or distribution of gas by pipeline or the storage of gas in or affecting interstate or foreign commerce.

4. Notice of Proposed Construction

At least forty-eight hours prior to the start of construction of pipeline installations, notice shall be filed with the D.P.U. in accordance with the requirements listed below:

(a) Pipeline installation projects of 5000 feet or more in length: ALL such projects.

(b) Pipeline installation projects of 2500 feet to 5000 feet in length: 25 per cent or a maximum of three of the projects in a calendar year.

(c) If no pipeline installation projects in a calendar year meet the requirements of (a) and (b), then there shall be reported to the D.P.U. no less than three pipeline installations irrespective of the length, provided ~~this number~~ or more are undertaken.

5. Nothing contained herein shall conflict with D.P.U. 14725 aining to the maintenance of records.

6. Notwithstanding any provision of the MFS Standards which may allow less stringent requirements, the following additional rules or modifications shall apply.

A. Low pressure distribution system. (Section 192.3 MFS Standards). For the purpose of this regulation a low pressure distribution system shall be defined as any system in which the gas pressure in the main is equal to or less than 2 psig.

B. Intermediate Pressure Distribution System. (Section 192.3 MFS Standards). For the purpose of this regulation, an intermediate pressure distribution system shall be defined as any system in which the gas pressure in the main is greater than 2 psig but equal to or less than 60 psig.

C. High pressure distribution system. (Section 192.3 MFS Standards). For the purpose of this regulation a high pressure distribution system shall be defined as a system in which the pressure in the main is greater than 60 psig but equal to or less than 200 psig.

D. Class locations. (Section 192.5 MFS Standards).

(g) Gas pipelines which are to be operated at pressures in excess of 200 psig, shall not be installed within forty feet of any building intended for human occupancy unless class 4 construction design criteria are met, or such other design criteria as the D.P.U. shall require.

(h) For the purpose of this regulation, every gas piping system shall be designed, constructed, tested, operated and maintained using a class 3 location as a minimum class location designation.

E. <u>Design of Plastic Pipe</u> (Section 192.121 MFS Standards)

(c) Plastic pipe shall not be used as gas carrier on any gas system unless it is resistant to chemicals with which contact may be anticipated.

(d) A typical plastic piping plan shall be submitted to the D.P.U. by all gas corporation and municipal departments before any plastic piping installation is made. Said plans shall include details concerning: (only class 3 and class 4 designation factors allowed).

1. Type of plastic pipe to be used as the gas carrier by specification. If the specifications are changed, a revised plan shall be submitted.

2. Method of connection to existing main and/or remaining portion of the service line. (Joints made by other than mechanical means must be made in accordance with the pipe manufacturer's recommended practices.)

   The casing pipe shall be prepared to the extent necessary to remove any sharp edges, projections or abrasive material that could damage the plastic during and after insertion.

3. Depth of cover.

4. When gas lights or other appliances are installed on the service line, the method of connection shall be detailed on a typical plan.

F. <u>Design Limitations for Plastic Pipe. (Section 192.123 MFS Standards.)</u>

(c) The wall thickness for thermoplastic pipe may not be less than 0.090 inches.

(d) The Department may approve high tensile strength plastic pipe with wall thickness of less than 0.090 inches.

G. <u>Design of Copper Pipe</u> (Section 192.125 MFS Standards)

(e) A typical copper service installation plan shall be submitted to the D.P.U. by all gas corporations and municipal gas departments for approval before any copper services are installed.

The letter of submittal shall state that the gas in these services will not contain more than an average of 0.3

grains of hydrogen sulfide per 100 standard cubic feet of gas and the service pressure does not exceed 100 psig. (See also Chapter 164, section 109 which prohibits any hydrogen sulfide).

H. Distribution line valves. (Section 192.181 MFS Standards).

(a) Each high pressure and intermediate pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of mains, and the local physical conditions.

I. Control of the pressure of gas delivered from high pressure tribution system. (Section 192.197 MFS Standards).

For the purpose of this regulation, Section 192.197 of the MFS andards shall be entitled: "Control of the pressure of gas delivered from mains operating at higher pressures than the pressure provided to the customer".

J. Required capacity of pressure relieving and limiting stations. ction 192.201 MFS Standards).

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station controlling the pressure to a system operating at a pressure that is substantially the same as the pressure provided to the customer, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

K. <u>Inspection and test of welds</u>. (Section192.241 MFS Standards)

(d) Notwithstanding the requirements of paragraph (b), not less than 10% of the welds randomly sampled over the length of at least three of the installations of which notice of construction is required under section 4 of this order shall be radiographically examined and available to the D.P.U. If less than three installation projects are undertaken by any company, at least 10% of the welds shall be radiographically examined and available to the D.P.U.

(3) The D.P.U. may at any t ime visually inspect any welding and if it is considered faulty, order the operating company to subject the weld to a destructive test as outlined in paragraph I of Appendix C of the MFS Standards or to a radiographic examination.

L. <u>Protection from Hazards</u>. (Section 192.317 MFS Standards).

(c) A typical plan shall be submitted to the D.P.U. showing construction details in areas of unstable soils.

(d) All new piping on bridges shall be limited to a maximum pressure of 100 psig.

(e) The method of protecting all new piping on trestles and bridges shall be subject to the approval of the D.P.U.

(f) Request for approval for all such bridge crossings shall be submitted to the D.P.U. with a detailed plan. The following items must be included on the request and/or plan.

1. The pipe size and the wall thickness (minimum wall thickness shall be 0.237 inches).

2. For nominal pipe sizes 12 or greater, calculations indicating the basis for wall thickness.

3. Method of providing for expansion or contraction of the bridge if necessary.

4. Pipe support details, number of supports, and distance between supports.

5. The plan shall indicate that valves areprovided on both sides of the bridge in the bridge approaches.

6. The operating pressure of the main and the test pressure.

(g) For bridges under the care and control of the Massachusetts Department of Public Works, procedure for a Department of Public Works permit shall be as follows:

1. On new bridges a preliminary design plan will be submitted by the Department of Public Works to the pertinent utility company notifying them of the proposed construction and suggested location of pipe on or in the bridge structure. (A copy of this letter will be forwarded to the Chief Engineer of the Department of Public Utilities).

2. The utility company will submit a plan to the Department of Public Utilities within thirty days of the receipt of the aforedescribed design plan if any construction is proposed on the particular bridge.

3. No permit for the installation of gas facilities on bridges will be considered unless the Department of Public Works has received from the Department of Public Utilities a letter approving the design.

4. All requests for permits for gas facilities on new bridges shall be directed to the Highway and Structures Engineer of the Massachusetts Department of Public Works.

5. All requests for new gas facilities on existing bridges shall be directed to the Maintenance Engineer of the Department of Public Works.

K. Casing (Section 192.323 MFS Standards).

Where a pipeline is or is to be subjected to a maximum operating pressure in excess of 200 psig, it shall not be laid or maintained (for the purpose of this section main-tained shall mean any action of moving, replacing or changing the pipeline for the purposes of upkeep, repair, renewal or replacement) under a highway pavement or under a railroad except where it is necessary to cross a highway or railroad. Whenever such crossings are required, they shall be made as nearly as practicable, to an angle of 90° to the center line of the highway or railroad. In the case of a railroad or highway crossing, the pipe shall be enclosed in a casing. Each casing used on a transmission line or main under a highway or railroad must comply with the following.

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 per cent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

(e) In addition to (a), (b), and (c) and (d) above, casings under railroads in which the gas carrier pipe is or is to be subjected to operating pressure in excess of 200 psig shall meet the requirements of the specification in API Code No. 1102 (September 1968) issued by the American Petroleum Institute Recommended Practice on Form of Agreement and Specifications for Pipeline Crossings under Railroad Tracks.

(f) Casings under highways in which the gas carrier pipe is or is to be subjected to operating pressures in excess of 200 psig, shall be designed in accordance with (e) of this section except that the minimum distance from the top of the casing to the used surface of the road shall be four feet, six inches (4'-6") and the casing shall extend beyond the edges of the pavement or of the used surface of the road where there is no pavement, a distance of not less than twenty-five (25) feet or to the line of the right of way whichever is the lesser. (See also Chapter 164, section 72 of the General Laws of Massachusetts).

N. Cover. (Section 192.327 MFS Standards)

(a) Except as provided in paragraph (c) of this section each buried transmission line must be installed with a minimum cover as follows·

Location	Normal Soil Inches	Consolidated Rock Inches
Class 3 and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

(b) Gas mains to be installed in highways under the jurisdiction and control of the Massachusetts Department of Public Works shall be laid with a minimum cover of thirty-six (36) inches from the top of the main to the used surface of the road.

(c) Except as provided in paragraphs (d) and (e) of this section, each buried main must be installed with at least 24 inches of cover.

(d) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(e) A main may be installed with less than 24 inches of cover providing:

1. Adequate measures are taken to prevent damage to the pipe by external forces.

2. That the maximum allowable operating pressure will produce a stress level of less than 20 per cent of SMYS.

3. That the D.P.U. approves the installation.

O. Service Lines. Valve Requirements (Section 192.363 MFS Standards).

(c) Each service line valve on an intermediate pressure or high pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

P. Service Lines Location of Valves. (Section 192.365 MFS Standards.

(d) All intermediate and high pressure services and all services 2" in diameter or larger shall be equipped with an underground curb shut-off located in proximity to the property line except that whenever gas is supplied to a theatre, church, school, factory or other building where large numbers of persons assemble, an outside shut off in such case will be required regardless of the size of the service or of the service pressure. All underground curb shut offs shall be readily identifiable and available for easy access by gas company personnel.

Q. Test requirements for pipelines to operate at a hoop stress less than 30 per cent of SMYS and above 75 psig. (Section 192.507 MFS Standards).

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 per cent of SMYS and above 75 psig, must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will insure discovery of any leak in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 per cent or more of SMYS and natural gas, inert gas, or air is the test medium

1. A leak test must be made at a pressure between 75 psig and the pressure required to produce a hoop stress of 20 per cent of SMYS or
2. The line must be walked to check for leaks while the hoop stress is held at approximately 20 per cent of SMYS.

(c) Steel gas mains to be operated at pressures from 75 psig to 150 psig shall be air or hydrostatically tested for tightness to 1.5 times the maximum allowable operating pressure for at least one hour.

(d) Steel gas mains to be operated at pressures in excess of 150 psig shall be air tested or hydrostatically tested for tightness to 1.5 times the maximum operating pressure for at least four hours and may be witnessed by the D.P.U. Calibrated recording instruments shall be verified by dead weight instruments and the recording submitted to the D.P.U. for certification that the steel gas main as defined may be operated at a pressure which is equal to the test pressure divided by a factor of 1.5.

R. Test requirements for pipelines to operate at or below 5 psig. (Section 192.509 MFS Standards).

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at or below 75 psig must be leak tested in accordance with the following:

(a) Th e test procedure used must insure discovery of any leaks in the segment being tested.

(b) At a test pressure of at least 90 psig for at least one hour.

(c) The tie-in joints to the live gas main, cast iron or steel, shall be tested using the soap bubble test.

S. Test requirements for service lines. (Section 192.511 MFS tandards).

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section be- fore being placed in service. If feasible, the service line connection to the main must be included in the test. if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) to operate at not more than 100 psig shall be tested after construction and before being placed into service to at least 90 psig for not less than 15 minutes. Leakage is not permissible.

(c) Each segment of a service line (other than plastic) to operate at pressures in excess of 100 psig must be tested in accordance with section 192.507 of the MFS Standards.

T. Test Requirements for Plastic Mains and Services.
(Section 192.513 MFS Standards)

(b) The test procedure must insure discovery of all leaks in the segment being tested.

(c) The test pressure shall be at least 150 per cent of the maximum operating pressure or 90 psig whichever is greater, for at least one hour for mains and at least 15 minutes for services. However, the maximum test pressure may not be more than three times the design pressure of the pipe.

U. Maximum allowable operating pressure intermediate pressure and high pressure distribution systems. (Section 192.621 MFS Standards)

(a) No person may operate a segment of an intermediate pressure or high pressure distribution system at a pressure that exceeds the lowest of the applicable pressures shown in Sections 192.621(a), (1), (2), (3), (4), (5), and (b)) of the MFS Standards.

V. Odorization of gas. (Section 192.625 MFS Standards.

All combustible gas distributed regardless of pressure shall have a distinctive odor of sufficient intensity so that a concentration of fifteen hundredths of one per cent gas in the air is readily perceptible to the normal or average olfactory senses of a person coming from fresh uncontaminated air into a closed room containing one part of the gas in 666 parts of air.

(a) The odorant shall be harmless to humans, non toxic and shall be non-corrosive to materials used in pipeline systems. It shall not be soluble in water to an extent greater than 2.5 parts by weight of the odorant to 100 parts by weight of water.

(b) The products of combustion from the odorant shall be non toxic to a person breathing air containing these products of combustion, and shall not be corrosive or harmful to materials which would normally be exposed to such products of combustion.

(c) Equipment for the introduction of the odorant into the gas shall be so designed and built as to avoid wide variations in the level of the odor in the gas. Equipment and facilities for handling the odorant shall be located where the escape of odorant would not be a nuisance.

(d) Each operator shall conduct periodic sampling of the combustible gases to assure the proper concentration of odorant in accordance with this section.

W. Distribution systems leakage surveys and procedures. (Section 192.723 MFS Standards).

Each operator having a gas distribution system shall conduct leakage surveys, as frequently as experience and technology indicates they are necessary, but in no event shall such leakage surveys be less than the following minimum standards

(a) Business Districts.

A gas detector survey must be conducted in business districts including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding one year. In areas where an effectively prescribed and supervised survey of electric or other manholes and vaults is conducted and offers more frequent coverage than the previous, such survey procedure may be substituted.

Business districts are defined as areas with pavement from building wall to building wall and/or where the principal commercial activity of the city or town takes place, said areas shall be outlined on a map and filed with the Department.

(b) Distribution System Areas Not Included in the Principal Business District.

Leakage surveys shall be made of the area not included in the principal business district at least once in every consecutive twenty-four month period. The method used for these leakage surveys shall include one or more of the following:

1. gas detector surveys using combustible gas indicators, flame-ionization equipment, infrared equipment or other industry accepted and proved testing equipment.
2. bar tests.
3. vegetation surveys.
4. pressure drop tests.

(c) Buildings of Public Assembly.

A survey of buildings of public assembly, including schools, churches, hospitals and theatres shall be conducted at least once annually. The survey shall include tests for gas leakage and visual inspection of gas facilities in the immediate area of the service entrance.

(d) Hazardous Conditions Repaired.

All disclosed conditions of a nature hazardous to persons or property shall be promptly made safe and permanent repairs instituted.

(e) Leak Detection Survey Records.

Records of the leak detection surveys shall be made and kept on file at the gas utility office for a period of time not less than the interim between successive surveys. Such records shall include

1. approximate mileage of mains surveyed.
2. leak repair data.

Appendix 4

December 8, 1980

D.P.U. 11725-G (Section One)

Investigation by the Department on its own motions as to the adoption of additional amendments to its gas distribution code (D.P.U. 11725-F, Section One) dated June 14, 1972, incorporating by reference Part 192 in Title 49 Code of Federal Safety Regulations, Transportation of Natural and Other Gas by Pipeline Minimum Federal Safety Standards and Amendments thereto, to be promulgated pursuant to the provisions of General Laws, Chapter 30A, Section 2 and Chapter 164, Sections 66, 76 and 105A.

The Department conducted an investigation on its own motion as to the adoption of proposed regulations to be promulgated pursuant to the provisions of the General Laws, Chapter 30A and Chapter 164, Sections 66, 76 and 105A. The proposed regulations supersede existing regulations contained in Section One of the Department's Gas Distribution Code in D.P.U. 11725-G. The Department duly advertised and held a public hearing upon the foregoing investigation on Wednesday, August 15, 1980, at its hearing room, 1210 Leverett Saltonstall Building, 100 Cambridge Street, Boston, Massachusetts. The hearing notice stated that copies of the proposed regulations were on file at the offices of the Department at 100 Cambridge Street, Boston, during normal business hours, and that presentation of data, views or arguments relating to the proposed regulations could be submitted by any interested persons orally at the public hearing or could be filed with the Department prior to such hearing.

Subsequent to the issuance of D.P.U. 11725-G, Section One on July 29, 1979, the Office of Pipeline Safety issued amendments 192.34, 192.35A and 192.35A to Part 192 that are not presently included in D.P.U. 11725-G. Amendments 192.34 and 192.34A refer to the procedures for joining plastic pipe, qualifying personnel to make plastic pipe joints, and the inspection of these joints, 192.35A is specifically directed to cathodic protection of transmission pipeline operations over which this Department has no authority, however, it has been included for continuity with the other amendments to various sections to which they are referred within Part 192. This investigation was for the purpose of considering the adoption of these amendments as a part of the Department's own code in D.P.U. 11725.

Pursuant to the provisions of the General Laws, Chapter 30, Section 2 and Chapter 164, Sections 66, 76 and 105A and after due notice, public hearing and consideration, it is hereby

ORDERED: That Section One of the Massachusetts Gas Distribution Code (D.P.U. 11725-G) be and hereby is terminated and that a new Section One of the Massachusetts Gas Distribution Code (D.P.U. 11725-H) in the form attached hereto be and hereby is adopted in place thereof as the regulations of the Department relating to the subjects covered thereby, including Amendments 192.1 published October 21, 1970, including all the other amendments consecutively published at various dates up to and including 192.35A published on April 7, 1980.

And it is

FURTHER ORDERED: That a copy of this Order and said new regulations be placed on file with the Secretary of State of the Commonwealth of Massachusetts.

And it is

FURTHER ORDERED: That this investigation be and hereby is terminated.

By Order of the Department,

/s/ DORIS R. POTE
Doris R. Pote
Chairman

A true copy
Attest;

Christopher C. Rich
Secretary

December 8, 1980

D.P.U. 11725-H
220 CMR 100.00

MASSACHUSETTS GAS DISTRIBUTION CODE

ORDERED: Pursuant to Sections 66, 76 and 105A of Chapter 164 of the General Laws, as amended, and after due notice and hearing, the Department of Public Utilities (D.P.U.) hereby adopts rules to insure safe operating practices of gas corporations and municipalities subject to said Chapter 164, engaged in the distribution of gas.

Every gas corporation and municipal gas department engaged in the distribution of gas within the Commonwealth of Massachusetts shall be governed by the rules hereinafter enumerated. Such rules shall apply to all new construction and new installations made subsequent to the effective date of these regulations and shall not apply retroactively to existing installation.

Section 1

1. Compliance with FMS Standards (101.01)

Every gas piping system shall be constructed, operated and maintained, except as otherwise provided in this regulation, in compliance with the provisions of: Part 192 in Title 49, Code of Federal Regulations, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, published August 19, 1970, including the following amendments: 192-1, published October 21, 1970, through 192-35A, published April 7, 1980, (referred to herein as the MFS Standards). Subsequent amendments, additions or revisions to the MFS Standards shall be reviewed by the Department. Changes of technical import which would affect the operation of gas distribution companies in Massachusetts shall be considered at a public hearing at the earliest opportunity, but within a year's time of the date of issuance. The D.P.U. will maintain a reference file containing the aforementioned federal regulations and incorporated documents.

2. Applications for Exceptions and Waivers from Provisions of the D.P.U. Regulations (101.02)

(a) A gas corporation or municipal gas department may make a written request to the D.P.U. for an exception to the provisions of paragraphs 4, 5 and 6 of Section One of this regulation (220 CMR 101.04, 101.05 and 101.06). The D.P.U. may, after consideration, and the payment of the appropriate fee, issue exception requested or modifications thereof to the particular gas corporation or municipality requesting such exception. In emergencies, a verbal exception may be granted by the D.P.U. which will then be confirmed by written request within seven (7) days.

(b) The D.P.U. may issue a waiver to a gas corporation or municipal gas department from the provisions of Part 192 in Title 49 of the Federal Regulations providing that the waiver pertains to an intrastate facility and the D.P.U. gives notice of such waivers to the Department of Transportation at least sixty (60) days before the waiver becomes effective.

3. Listing of Definitions Contained in Part 192 (Subpart A Section 192.3 of the MFS Standards (101.03)

As used in this part:

"Distribution Line" means a pipeline other than a gathering or transmission line.

"Gas" means natural gas, flammable gas, or gas which is toxic or corrosive.

"Gatherine Line" means a pipeline that transports gas from a current production facility to a transmission line or main.

"High pressure distribution system" means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer. (See paragraph 6 of this regulation) (220 CMR 101.06)

"Listed Specification" means a specification listed in Section 1 of Appendix B of this part.

"Low pressure distribution system" means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer. (See paragraph 6 of this regulation) (220 CMR 101.06)

"Main" means a distribution line that serves as a common source of supply for more than one service line.

"Maximum actual operating pressure" means the maximum pressure that occurs during normal operations over a period of one (1) year.

"Maximum allowable operating pressure" means the maximum pressure of which a pipeline or segment of a pipeline may be operated under this part.

"Municipality" means a city, county or any other political subdivision of a State.

"Offshore" means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with open seas and beyond the line marking the seaward limit of inland waters.

"Operator" means a person who engages in the transportation of gas.

"Person" means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association or joint stock association, and includes any trustee, receiver, assignee or personal representative thereof.

"Pipe" means any pipe or tubing used in the transportation of gas, including pipe-type holders.

"Pipeline" means all parts of those physical facilities through which gas moves in transportation, including pipe, valve and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.

"Pipeline Facility" means new and existing pipelines, rights-of-way and any equipment facility or building used in the transportation of gas or in the treatment of as during the course of transportation.

"Secretary" means the Secretary of Transportation or any person to whom he has delegated authority in the matter concerned.

"Service Line" means a distribution line that transports gas from a common source of supply to (a) a customer meter or the connection to a customer's piping, whichever is farther downstream, or (b) the connection to a customer's piping if there is not customer meter. A customer meter is the meter that measures the transfer of gas from an operator to a consumer.

"SMYS" (specified minimum yield strength) is: (1) for steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification, or (2) for steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with 192.107 (b).

"State" means each of the several states, the District of Columbia, and the Commonwealth of Puertc Rico.

"Transmission Line" means a pipeline, other than a gathering line that: (1) Transports gas from a gathering line or storage facility to a distribution center or storage facility; (2) Operates at a hoop stress of 20 percent or more of SMYS; or (3) Transports gas within a storage field.

"Transportation of Gas" means the gathering, transmission or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

4. Notice of Proposed Construction (101.04)

At least forty-eight (48) hours prior to the start of construction of pipeline installation, notice shall be filed with the D.P.U. in accordance with the requirements listed below:

(a) Pipeline installation projects of 5000 feet or more in length, ALL such projects.

(b) Pipeline installation projects of 2500 feet to 5000 feet in length; twenty-five (25) percent or a maximum of three (3) of the projects in a calendar year.

(c) If no pipeine installation projects in a calendar year meet the requirements of (a) and (b) (220 CMR 101.04 (a) and (b), then there shall be reported to the D.P.U. no less than three pipeline installations irrespective of the length, provided this number or more are undertaken.

5. Nothing contained herein shall conflict with D.P.U. 14725 pertaining to the maintenance of records. (101.05)

6. Notwithstanding any provisions of the MFS Standards which may allow less stringent requirements, the following additional rules or modifications shall apply: (101.06)

A. Low pressure distribution system. (Section 192.3 MFS Standards) For the purpose of this regulation, a low pressure distribution system shall be defined as any system in which the gas pressure in the main is equal to or less than 2 psig.

B. Intermediate pressure distribution system. (Section 192.3 MFS Standards) For the purpose of this regulation, an intermediate pressure distribution system shall be defined as any system in which the gas pressure in the main is greater than 2 psig but equal to or less than 60 psig.

C. High pressure distribution system. (Section 192.3 MFS Standard) For the purpose of this regulation, a high pressure distribution system shall be defined as a system in which the pressure in the main is greater than 60 psig but equal to or less than 200 psig.

D. Class Locations. (Section 192.5 MFS Standards)

(g) Gas pipelines which are to be operated at pressures in excess of 200 psig, shall not be installed within forty (40) feet of any building intended for human occupancy unless class 4 construction design criteria are met, or such other design criteria as the D.P.U. shall require.

(h) For the purpose of this regulation, every gas piping system shall be designed, constructed, tested, operated and maintained using a class 3 location a minimum class location designation.

E. Design Limitations for Plastic Pipe. (Section 192.123 MFS Standards)

(c) The wall thickness for thermoplastic pipe may not be less than 0.090 inches.

(d) The D.P.U. may approve the use of reinforced thermosetting plastic pipe having a wall thickness not less than that listed in the following table:

Nominal Size in Inches	Minimum Wall Thickness in Inches
2	0.060
3	0.060
4	0.070
6	0.100

F. Distribution Line Valves. (Section 192.181 MFS Standards)

(a) Each high pressure and intermediate pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of mains and the local physical conditions.

G. Control of the pressure of gas delivered from high pressure distribution system. (Section 192.197 MFS Standards)

For the purpose of this regulation, Section 192.197 of the MFS Standards shall be entitled: "Control of the pressure of gas delivered from mains operating at higher pressures than the pressure provided to the customer."

H. Required capacity of pressure relieving and limiting stations. (Section 192.201 MFS Standards)

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station controlling the pressure to a system operating at a pressure that is substantially the same as the pressure provided to the customer, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

I. Inspection and Test of Welds. (Section 192.241 MFS Standards)

(d) Notwithstanding the requirements of paragraph (b) (192.241 MFS Standards) (b), not less than ten percent of the welds randomly sampled over the length of at least three of the installations of which notice of construction is required under Section 4 (220 CMR 101.04) of this order shall be radiographically examined and available to the D.P.U. If less than three installation projects are undertaken by any company, at least 10 percent of the welds shall be radiographically examined and available to the D.P.U.

(e) The D.P.U. may, at any time, visually inspect any welding and if it is considered faulty, order the operating company to subject the weld to a destructive test as outlined in paragraph I of Appendix C of the MFS Standards or to a radiographic examination.

J. Protection from Hazards (Section 192.317 MFS Standards)

(f) The method of protecting all new piping on trestles and bridges shall be subject to the approval of the D.P.U. For each such bridge crossing, the operator shall submit a written request for approval and a detailed installation plan to the D.P.U. that includes the following items:

(1) The proposed nominal pipe diameter, wall thickness, (minimum wall thickness 0.237"), and the Specified Minimum Yield Strength. (SMYS)

(2) The maximum operating pressure of the pipeline and the test pressure. The maximum operating pressure for new pipelines on bridges shall not exceed 200 psig.

(3) For nominal pipe diameters 12" or greater a calculation of the hoop stress (H) in accordance with the following formula:

$$H = \frac{PD}{2t}$$

H = Hoop stress in pounds per square inch
P = Maximum operating pressure in pounds per square inch gauge
D = The specified outer diameter in inches
t = Specified wall thickness in inches (not less than 0.237")

(4) Method of providing for expansion or contraction of the bridge, if necessary.

(5) Pipe support details, number of supports, and distances between supports.

(6) The plan shall indicate that valves are provided on both sides of the bridge and their approximate location.

(g) For bridges under the care and control of the Massachusetts Department of Public Works, procedure for a Department of Public Works permit shall be as follows:

(1) On new bridges, a preliminary design plan will be submitted by the Department of Public Works to the pertinent utility company notifying them of the proposed construction and suggested location of pipe on or in the bridge structure. (A copy of this letter will be forwarded to the Chief Engineer of the Department of Public Utilities.)

(2) The utility company will submit a plan to the Department of Public Utilities within thirty (30) days of the receipt of the aforedescribed design plan if any construction is proposed on the particular bridge.

(3) No permit for the installation of gas facilities on bridges will be considered unless the Department of Public Works has received from the Department of Public Utilities a letter approving the design.

(4) All requests for permits for gas facilities on new bridges shall be directed to the Highway and Structures Engineer of the Massachusetts Department of Public Works.

(5) All requests for new gas facilities on existing bridges shall be directed to the Maintenance Engineer of the Department of Public Works.

K. Casing (Section 192.323 MFS Standards) Where a pipeline is or is to be subjected to a maximum operating pressure in excess of 200 psig, it shall not be laid or maintained (for the purpose of this section, "maintained" shall mean any action of moving, replacing or changing the pipeline for the purposes of upkeep, repair, renewal or replacement) under a highway pavement or under a railroad except where it is necessary to cross a highway or railroad. Whenever such crossings are required, they shall be made as nearly as practicable, to an angle of 90° to the center line of the highway or railroad. In the case of a railroad or highway crossing, the pipe shall be enclosed in a casing. Each casing used on a transmission line or main under a highway or railroad must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibiity of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

(e) In addition to (a), (b), (c) and (d) above, (220 CMR 101.06 (K) (a) through 101.06 (K) (d)), casings under railroads in which the gas carrier pipe is or is to be subjected to operating pressure in excess of 200 psig shall meet the requirements of the specifications in API RP 1102 (September 1968) issued by the American Petroleum Institute, Recommended Practice for Liquid Petroleum Pipelines Crossing Railroads and Highways.

(f) Casings under highways in which the gas carrier pipe is or is to be subjected to operating pressures in excess of 200 psig shall be designed in accordance with (e) of this section except that the minimum distance from the top of the casing to the used surface of the road shall be four feet six inches (4" 6") and the casing shall extend beyond the edges of the pavement or of the used surface of the road where there is no pavement, a distance of not less than twenty-five (25) feet or to the line of the right-of-way, whichever is the lesser.

e Ch. 164, §73, M.G.L., and D.P.U. 12769, June 21, 1960.)

L. Cover (Section 192.327 MFS Standards)

(a) Except as provided in paragraph (c) of this section, (220 CMR 101.06 (L) (c), each buried transmission line must be installed with a minimum cover as follows:

Table I

Location	Normal Soil (inches)	Consolidated Rock (inches)
Class 3 and 4 locations	36	24
Drainage and ditches of public roads and railroad crossings	36	24

(b) Gas mains to be installed in highways under the jurisdiction and control of the Massachusetts Department of Public Works shall be laid with a minimum cover of thirty-six (36) inches from the top of the main to the used surface of the road.

(c) Except as provided in paragraphs (d) ana (e) of this section, each buried main must be installed with at least twenty-four (24) inches of cover.

(d) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(e) A main may be installed with less than twenty-four (24) inches of cover providing:

(1) Adequate measures are taken to prevent damage to the pipe by external forces.

(2) That the maximum allowable operating pressure will produce a stress level of less than twenty (20) percent of SMYS.

(3) That the D.P.U. approves the installation.

M. Service Lines. Valve Requirements. (Section 192.363 MFS Standards)

(c) Each service line valve on an intermediate pressure or high pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specified tools.

N. Service Lines. Location of Valves. (Section 192.365 MFS Standards)

(d) All intermediate and high pressure services and all services 2" in diameter or larger shall be equipped with an underground curb shut off located in proximity to the property line except that whenever gas is supplied to a theatre, church, school, factory or other building where large numbers of persons assemble, an outside shut-off in such case will be required regardless of the size of the service or of the service pressure. All underground curb shut-offs shall be readily identifiable and available for easy access by gas company personnel.

O. Test Requirements for Pipelines to operate at a hoop stress less than thirty (30) percentof SMYS and above 100 psig (Section 192.507 MFS Standards).

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than thirty (30) percent of SMYS and above 100 psig, must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested. However, loss of pressure due to leakage during the test period is not permitted.

(b) If, during the test, the segment is to be stressed to twenty (20) percent or more of SMYS and natural gas, inert gas or air is the test medium:

(1) A leak test must be made at a pressure between 100 psig and the pressure required to produce a hoop stress of twenty (20) percent of SMYS, or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately twenty (20) percent of SMYS.

(c) Steel gas mains to be operated at pressures from 100 psig to 150 psig shall be air or hydrostatically tested for tightness to 1.5 times the maximum allowable operating pressure for at least one hour.

(d) Steel gas mains to be operated at pressures in excess of 150 psig shall be air tested or hydrostatically tested for tightness to 1.5 times the maximum operating pressure for at least four (4) hours and may be witnessed by the D.P.U. Calibrated recording instruments shall be verified by dead weight instruments and the recording submitted to the D.P.U. for certification that the steel gas main as defined may be operated at a pressure which is equal to the test pressure divided by a factor of 1.5.

P. Test Requirements for Pipelines to operate at or below 100 psig. (Section 192.509 MFS Standards)

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at or below 100 psig must be leak tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested. However, loss of pressure due to leakage during the test period is not permitted.

(b) At a test pressure of at least 90 psig for at least one hour.

(c) The tie-in joints to the live gas main, cast iron or steel, shall be tested using the soap bubble test.

Q. Test Requirements for Service Lines. (Section 192.511 MFS Standards)

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test. If not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) to operate at not more than 100 psig shall be tested after construction and before being placed into service to at least 90 psig for not less than fifteen minutes. Pressure loss due to leakage during the test period is not permitted.

(c) Each segment of a service line (other than plastic) to operate at pressures in excess of 100 psig must be tested in accordance with section 192.507 of the MFS Standards.

R. Test Requirements for Plastic Mains and Services. (Section 192.513 MFS Standards)

(b) The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested. However, loss of pressure due to leakage during the test period is not permitted.

(c) The test pressure shall be at least 150 percent of the maximum operating pressure or 90 psig, whichever is the greater, for at least fifteen (15) minutes for services, or one hour for mains. However, the maximum test pressure may not be more than three (3) times the design pressure of the pipe.

S. Maximum Allowable Operating Pressure. Intermediate Pressure and High Pressure Distribution Systems. (Section 192.621 MFS Standards)

(a) No person may operate a segment of an intermediate pressure or high pressure distribution system at a pressure that exceeds the lowest of the applicable pressures shown in sections 192.621 (a), (1), (2), (3), (4), (5) and (b)) of the MFS Standards)

T. Odorization of Gas. (Section 192.625 MFS Standards)

(a) A combustible gas in a distribution line shall have a distinctive odor of sufficient intensity so that a concentration of fifteen hundredths of one percent gas in the air is readily perceptible to the normal or average olfactory senses of a person coming from fresh uncontaminated air into a closed room containing one part of the gas in 666 parts of air.

(b) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, material or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

(c) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(d) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(e) Equipment and facilities for handling the odorant shall be located so as to minimize the effect of an escape of odorant.

(f) Each operator shall conduct periodic samplings of the combustible gases to assure the proper concentration of odorant in accordance with this section.

U. Distribution Systems Leakage Surveys and Procedures. (Section 192.723 MFS Standards)

Each operator of a gas distribution system shall conduct leakage surveys, as frequently as experience and technology indicates they are necessary, but

In no event shall such leakage surveys be less than the following minimum standards:

(a) Business Districts

A gas detector survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding one (1) year. In areas where an effectively prescribed and supervised survey of electric or other manholes and vaults is conducted and offers more frequent coverage than the previous, such a survey procedure may be substituted.

Business districts are defined as areas with pavement from building wall to building wall and/or where the principal commercial activity of the city or town takes place. Such areas shall be outlined on a map and maintained by the operator.

(b) Distribution System Areas Not Included in the Principal Business District:

Leakage surveys shall be made of the area not included in the principal business district at least once in every consecutive twenty-four (24) month period.

(c) Type of Survey:

Leakage surveys for (a) and (b) of this section shall include one or more of the following:

(1) Gas detector surveys using combustible gas indicators, flame ionization equipment, infra-red equipment or other industry accepted and proved testing equipment.

(2) Bar tests.

(3) Vegetation surveys.

(4) Pressure drop tests.

(d) Other Surveys:

In addition to the requirements of (a) and (b) of this section, a survey of schools, churches, hospitals, theatres and arenas shall be conducted at least once annually. The survey shall include tests for gas leakage and visual inspection of gas facilities in the immediate area of the service entrance.

(e) Hazardous Conditions Repaired:

All disclosed conditions of a nature hazardous to persons or property shall be promptly made safe and permanent repairs instituted.

(f) Leakage Survey Records:

Records of the leakage surveys required under this section shall be maintained for a period of time not less than the interim between successive surveys.

V. Test Requirements for Reinstating Service Lines. Section 192.725 MFS Standards).

(c) For the purpose of this section, each service line, temporarily disconnected from the main and to be operated at a pressure not in excess of 1 psig, shall be tested at a pressure of at least 10 psig for not less than fifteen (15) minutes. Pressure loss due to leakage during the test period is not permitted.

(d) The operator shall make and retain a record of each pressure test required under 192.725.

Regulating Authority: 220 CMR 101.00 MGL: 164, 66, 76, 105A.

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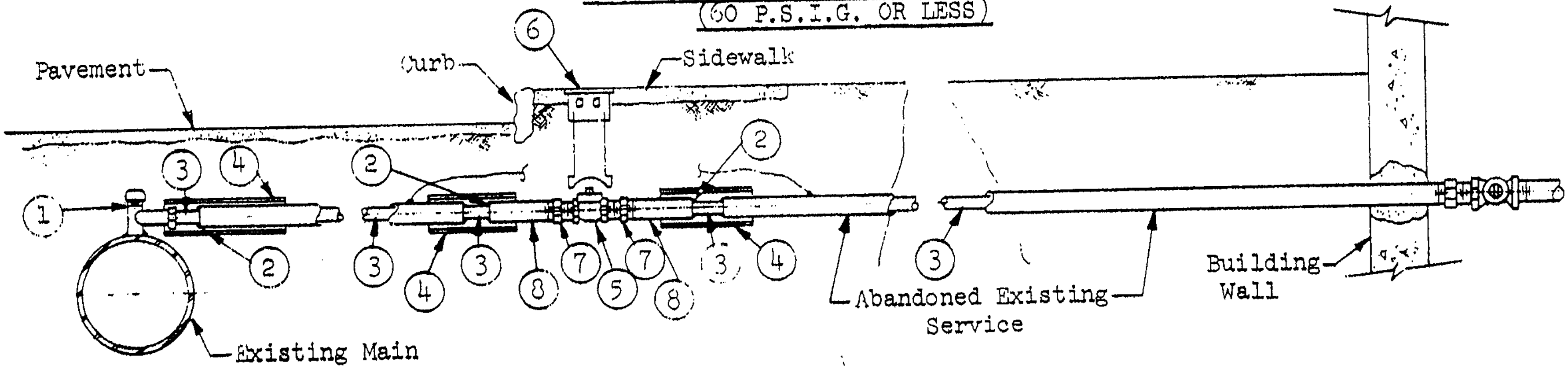
REV.	DATE		APP.	REV.	DATE		APP.
1	10/19/77	Revised Circle 5	JAM				6/2/76 -Gas Standards Comm. DATE 6/2/76 APPROVED JAM.

Appendix 5

SERVICE REPLACEMENT BY PLASTIC INSERTS
(60 P.S.I.G. OR LESS)



(1) Inlet Service Connection (M-145 Plastic Main)
(M-146 Cast Iron and Steel Main)
(M-143 Steel & Cast Iron Main - Use only with Plastic to Steel Transition Fitting)

(2) Plastic Pipe Protection

(3) Plastic Pipe (Service Insert) (M-252)

(4) Protective Sleeve (M-145)

(5) Outside Shut-off (M-51) with Plastic Pipe Adapter Fitting (M-146) or (M-61) without (7) (8)

(6) Curb Box (M-25)

(7) Plastic Pipe Adapter Fitting (M-146)

(8) Steel Pipe for Torsional Stability (M-251)

APPROVED Gas Standards Comm.-6/2/76
DATE 6/2/76

INSTALLATION INSTRUCTIONS:

a. Shut-off and make the required cuts to isolate the service section to be inserted.

b. Clean, ream and blow out the isolated section.

c. Insert the carrier pipe using a bull-nose protector on the forward end.

d. Make-up fittings between the plastic insert and the inlet service connection, the outside shut-off and at the thru wall service as required.

e. Provide protection around the carrier pipe at the ends of the casing pipe.

f. See C-245 for pressure test.

g. See C-247 for purging procedures.

h. See C-522 for proper corrosion protection.

i. Use pipe dope sealant at all threaded metal joints.

j. See C-173 for the handling and installation of plastic pipe.

k. See C-720 for safety procedures.

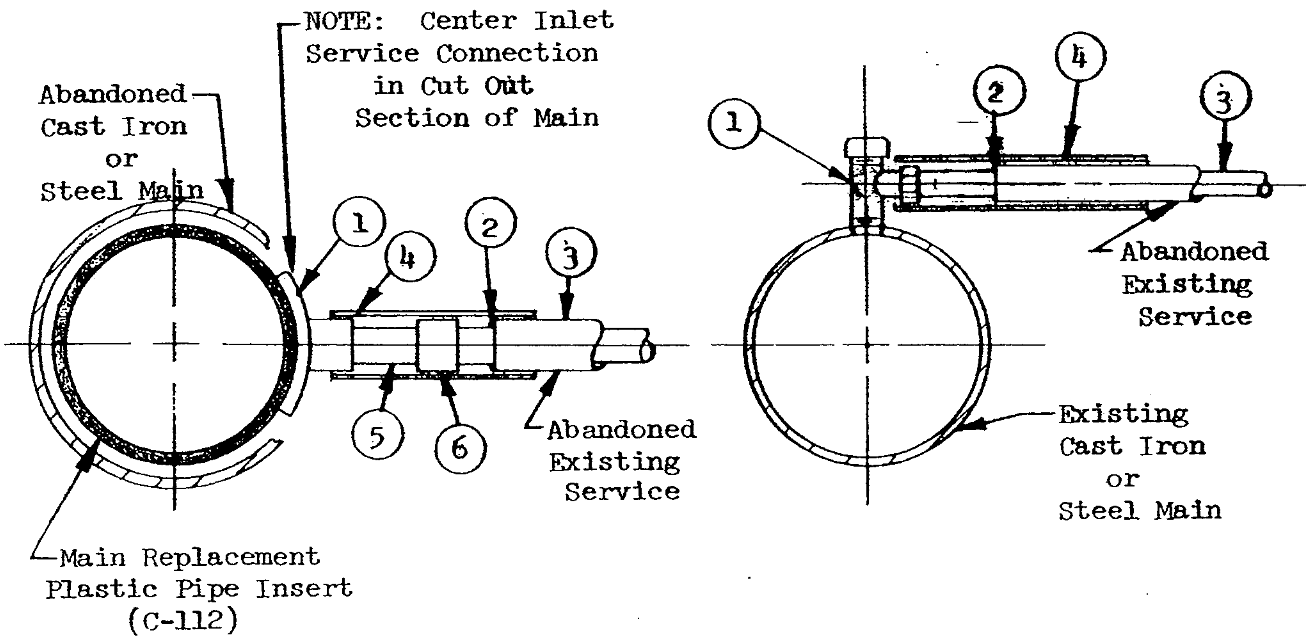
NOTE: Due to the fact that plastic pipe service replacements have been squeezed off by ice confined between it and the abandoned service it has been inserted in, the following should be considered in areas of known high water table:

1/2" Plastic should not be inserted in an abandoned service larger than 1" IPS.

3/4" Plastic should not be inserted in an abandoned service larger than 1 1/4" IPS.

REV. 1 DATE 3/8/78 Added j., k. & Note APP.

LOW PRESSURE
SERVICE CONNECTION TO CAST IRON, STEEL, AND PLASTIC MAINS
FOR SERVICE REPLACEMENT BY PLASTIC INSERTS



(1) Inlet Service Connection (Plastic Main M-145)
(Cast Iron & Steel Main M-146)

(2) Plastic Pipe Protection

(3) Plastic Pipe (Service Insert) (M-252)

(4) Protective Sleeve (M-145)

(5) Plastic Pipe (length as required according to manufacturers' tapping instructions) (M-252)

(6) Plastic Coupling (M-145)

INSTALLATION NOTES:

a. To install inlet service connection on plastic main, heat-fuse plastic tee and tap according to manufacturers' instructions. For steel and cast iron main refer to C-210.

b. Threaded taps in cast iron pipe are permitted without reinforcements to a size not more than 25% of the nominal diameter of the pipe except that $1\frac{1}{4}$" taps are permitted in 4" pipe. However, in areas where soil and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6" dia. or larger pipe. On larger taps, mechanical sleeves shall be used.

c. Install inlet service connection on main as shown or anywhere on or above the horizontal pipe centerline as required for depth of cover.

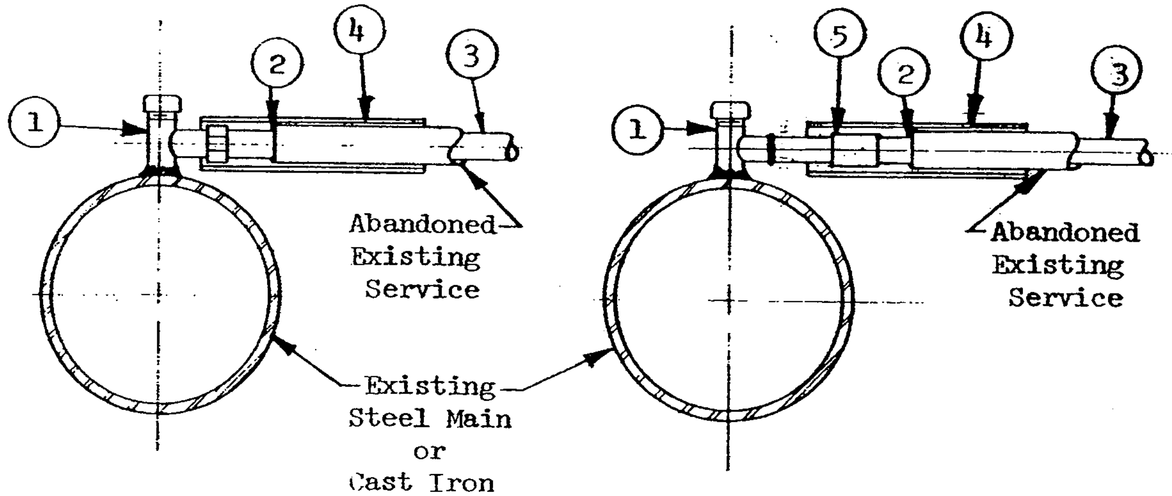
d. See C-522 for cathodic protection.

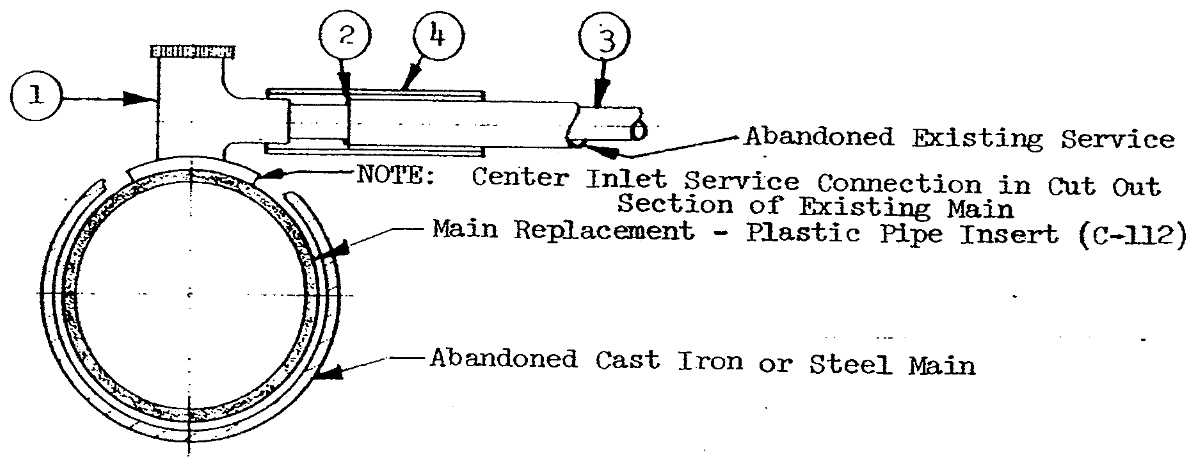
REV.	DATE		APP.
1	1-17-77	Rev. Note b.	
	6/2/76	-Gas Standards Comm.	
	DATE 6/2/76	APPROVED 7.9.77	

NEW ENGLAND GAS AND ELECTRIC SYSTEM

GAS STANDARDS - SERVICES

INTERMEDIATE PRESSURE
SERVICE CONNECTIONS TO STEEL, CAST IRON AND PLASTIC MAINS
FOR SERVICE REPLACEMENT BY PLASTIC INSERTS





(1) Inlet Service Connection (M-145 Plastic Main)
(M-146 Steel & Cast Iron Main)
(M-143 Steel & Cast Iron Main - Use only with Plastic to Steel Transition Fitting.)

(2) Plastic Pipe Protection

(3) Plastic Pipe (Service Insert) (M-252)

(4) Protective Sleeve (M-145)

(5) Plastic to Steel Transition Fitting (M-145)

INSTALLATION NOTES:

a. Weld/heat-fuse inlet service connections to main and tap according to manufacturer's instructions.

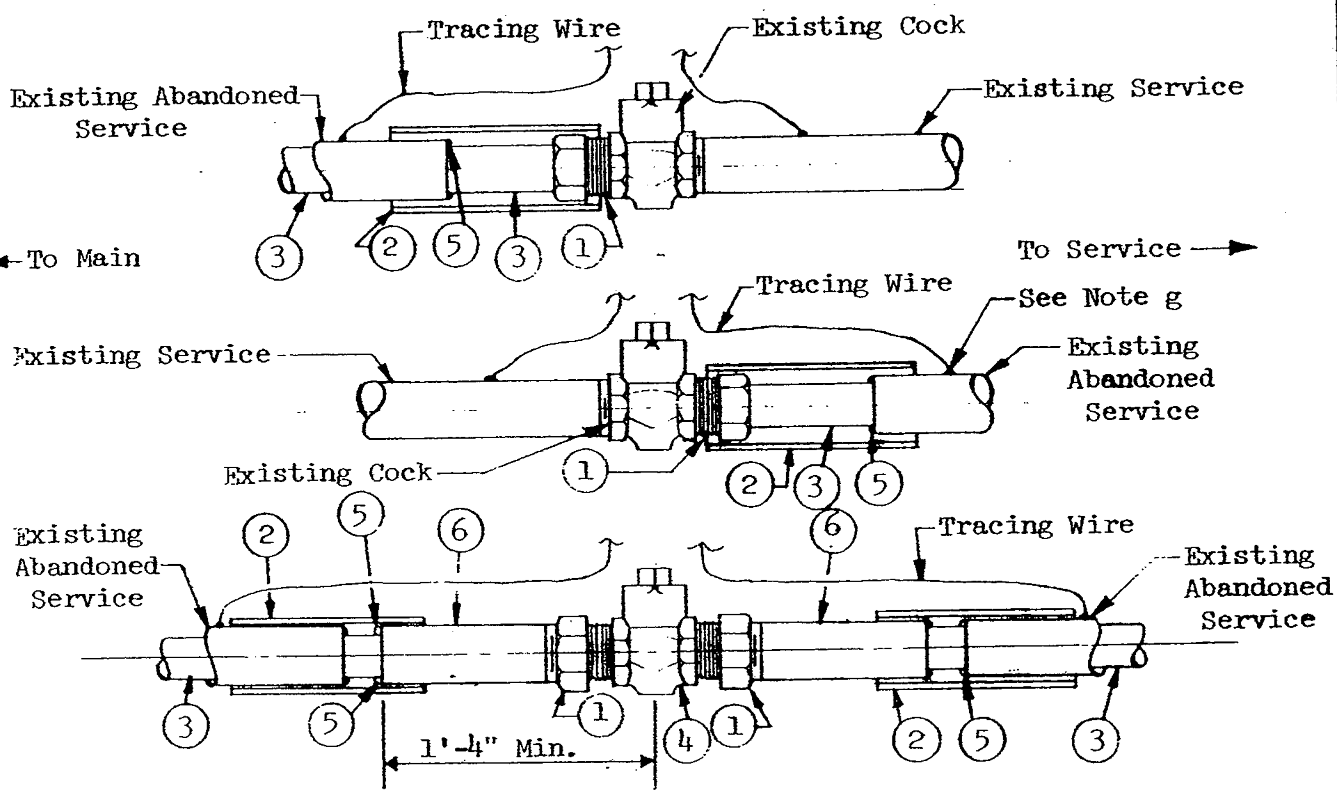
b. Inlet service connection is to be welded/heat-fused to main vertically, as shown, or anywhere on or above the horizontal pipe center line as required for depth of cover.

c. See C-522 for cathodic protection.

Gas Standards Comm. APPROVED
DATE 6/2/76 6/2/76

APPROVED Standards Comm. DATE 6/2/76 Gas Standards Comm. 6/2/76

INSTALLATION OF LOW AND INTERMEDIATE PRESSURE
OUTSIDE SHUT-OFF FOR SERVICE REPLACEMENT BY PLASTIC INSERTS



(1) Plastic Pipe Adapter Fitting (M-146)

(2) Fabricated Plastic Protective Sleeve (M-145)

(3) Plastic Pipe (Service Insert) (M-252)

(4) Outside Shut-Off (M-51) or (M-61) without (1)(5)(6)

(5) Plastic Pipe Protection

(6) Steel Pipe for Torsional Stability (M-251) Threaded One End

INSTALLATION NOTES:

a. Thermit weld prior to plastic pipe insert to avoid damage to plastic pipe.

b. See C-522 for Cathodic Protection.

c. Insert plastic pipe into plastic pipe adapter fitting according to manufacturer's instructions.

d. Use pipe dope sealant at all threaded metal joints.

e. In lieu of the above torsional stability method, alternate methods and systems to provide torsional stability must have prior approval by the Gas Distribution Superintendent or his delegate.

f. If existing shut-off cock is absent or unsuitable for continued service thread the end of the existing service and install a new cock (M-51).

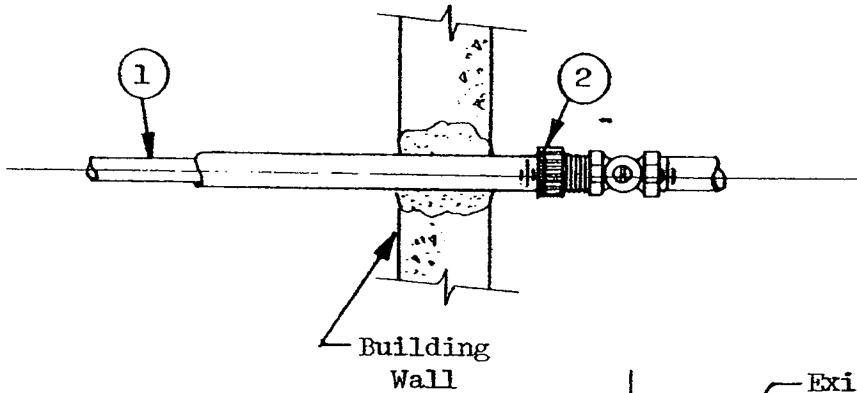
g. See C-592 for thermit weld.

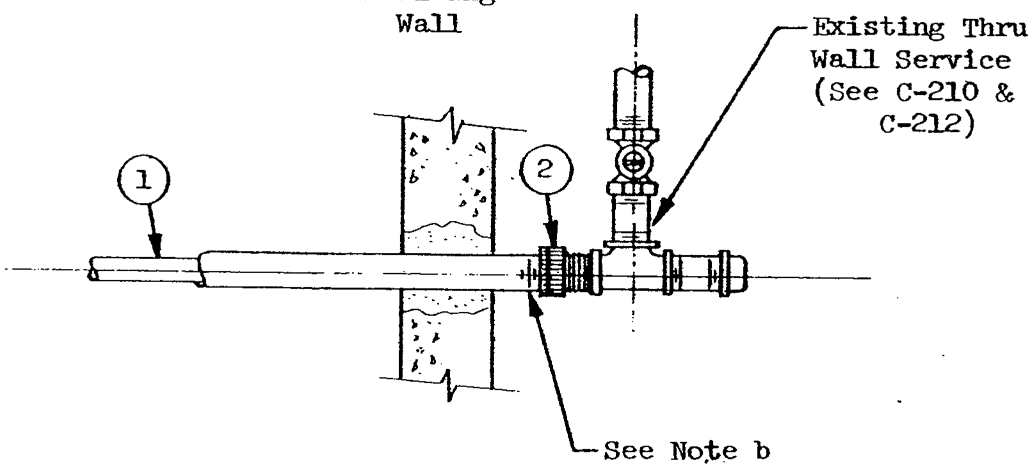
REV. 1 DATE 10/19/77 Revised Circle 4

NEW ENGLAND GAS AND ELECTRIC SYSTEM

GAS STANDARDS - SERVICES

INSTALLATION OF LOW AND INTERMEDIATE PRESSURE SERVICES THRU BUILDING WALL FOR SERVICE REPLACEMENT BY PLASTIC INSERTS





(1) Plastic Pipe (Service Insert) (M-252)

(2) Plastic Pipe Adapter Fitting (Service Head Renewal) (M-146)

INSTALLATION NOTES:

a. Optional use of an identification tag. If used, the identification tag shall be fastened on the existing thru-wall service at the plastic pipe adapter fitting and shall state:

CAUTION
PLASTIC INSERT
DO NOT REMOVE SERVICE HEAD RENEWAL FITTING

b. Use pipe dope sealant at all threaded metal joints.

6/2/76 - Gas Standards Comm.
APPROVED
DATE 6/2/76

FIGURE 1: PLASTIC INSERT AND THE INLET SERVICE CONNECTION

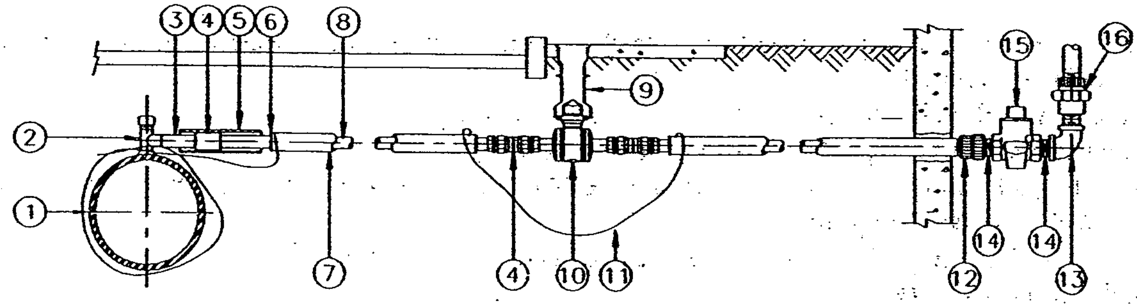


FIGURE 1a: INTERMEDIATE PRESSURE

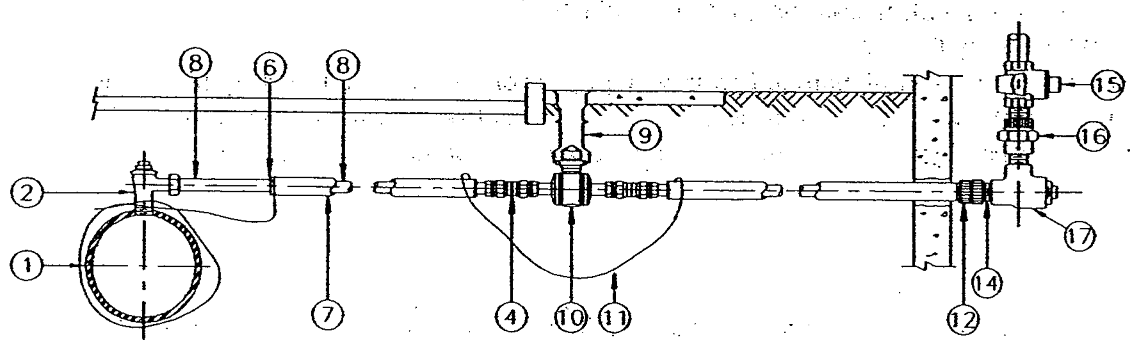


FIGURE 1b: LOW PRESSURE

1. Existing Main
2. Inlet Service Connection (Steel or Cast Iron Main M-143, Plastic M-145)(M-131, LP only)
3. Plastic-to-Steel Transition Fitting (M-135) or Welded Nipple (M-251)
4. Mechanical Coupling (M-122),Socket Fusion (M-145) or Electrofusion Coupling (M-140)
5. Protective Sleeve (M-135)
6. End Protector Bushing (M-118)
7. Abandoned Service
8. Plastic Pipe (Service Insert M-252)
9. Curb Box (M-27 or M-25)
10. Plastic Outside Shut-Off (M-61)
11. Tracer Wire
12. Plastic Pipe Adapter Fitting (Service Head Renewal M-146)
13. Elbow (M-138)
14. Nipple (M-251)
15. Inside Shut-Off (M-53). See Note a.
16. Insulated Union (M-163)
17. Approved Fitting (M-133)
18. Excess Flow Valve (M-306

NOTE: SEE PAGE 2 FOR NOTES

SERVICE REPLACEMENT BY PLASTIC INSERT 60 PSIG OR LESS

INSTALLATION INSTRUCTIONS

a. Shut off and make the required cuts to isolate the service section to be inserted. Insulate interior piping as close to the wall as possible.
b. Clean, ream, and blow out the isolated section when necessary.
c. Insert the Carrier Pipe, using a Bull-Nose Protector on the forward end.
d. Make up fittings between the Plastic Insert and the Inlet Service Connection, the Outside Shut-Off, and at the Through-Wall Service as required.
e. Provide protection around the Carrier Pipe at the ends of the Casing Pipe.
f. See C-245 for Pressure Test.
g. See C-522 for Corrosion Protection.
h. Use Pipe Dope Sealant at all threaded metal joints.
i. See C-173 for the Handling and Installation of Plastic Pipe.
j. See C-720 for Safety Procedures.
k. Bond isolated sections of abandoned service using tracer wire before inserting plastic pipe. Coil tracer wire around main without making metallic contact. For steel or cast iron main connect 17 pound magnesium anode to tap connection using thermit weld or mechanical clamp as appropriate.

NOTES

Due to the fact that plastic pipe service replacements have been squeezed off by ice confined between it and the abandoned service it has been inserted in, the following should be considered in areas of known high water table:

½" CTS Plastic should not be inserted in an abandoned service larger than 1" IPS.

¾" CTS Plastic should not be inserted in an abandoned service larger than 1¼" IPS.

" CTS Plastic should not be inserted in an abandoned service larger than 2" IPS.

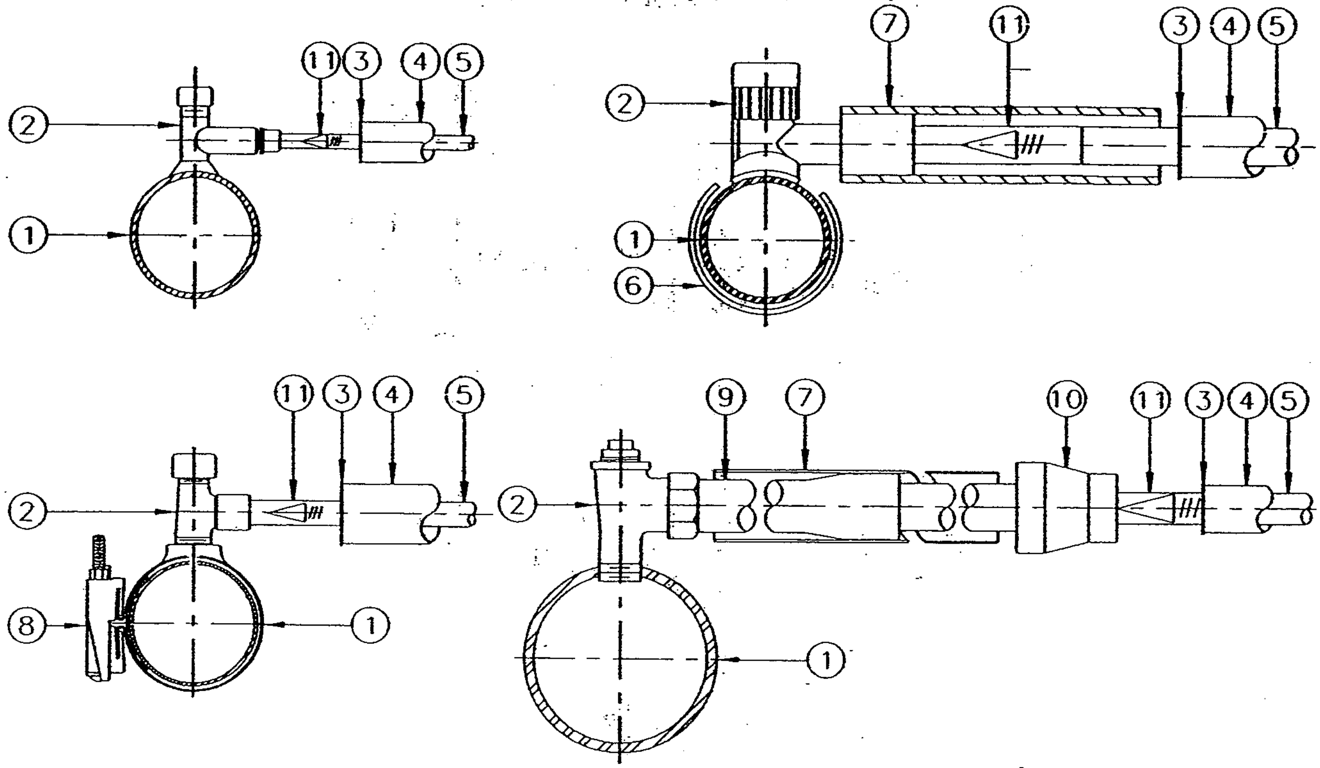
¼" CTS Plastic should not be inserted in an abandoned service larger than 3" IPS.

¼" IPS Plastic should not be inserted in an abandoned service larger than 3" IPS.

" IPS Plastic should not be inserted in an abandoned service larger than 4" IPS.

" IPS Plastic should not be inserted in an abandoned service larger than 10" IPS.

FIGURE 2: LOW AND INTERMEDIATE-PRESSURE SERVICE CONNECTION TO CAST IRON, STEEL AND PLASTIC MAINS

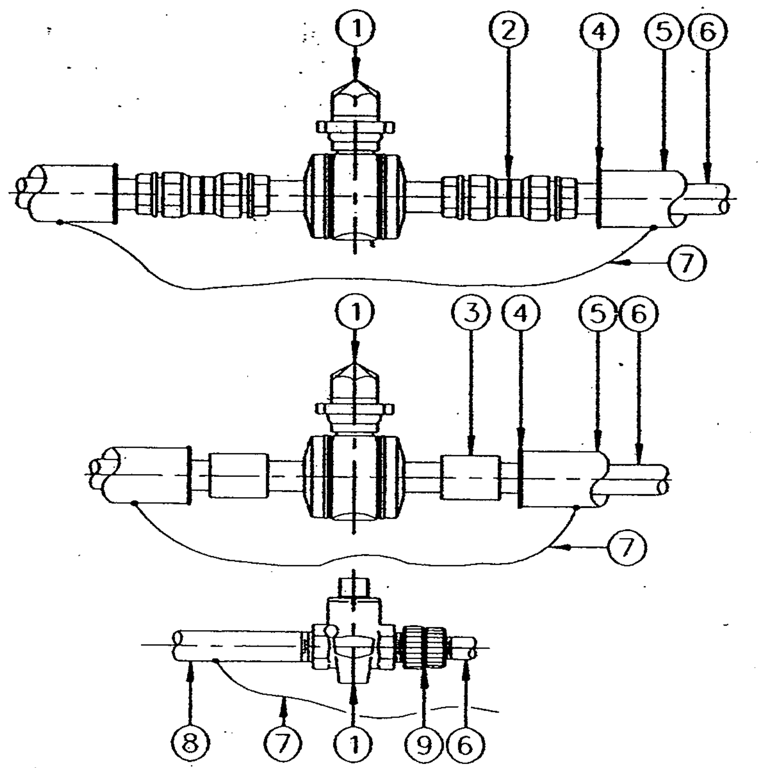


1. Existing Main
2. Inlet Service Connection (Steel or Cast Iron Main M-143, Plastic M-145)
3. End Protector Bushing (M-118)
4. Abandoned Service
5. Plastic Pipe (M-252)
6. Abandoned Steel or Cast Iron Main
7. Protective Sleeve (M-135)
8. Mechanical Sleeve (M-150)
9. Plastic-to-Steel Transition Fitting (M-135)
10. Fusion Coupling (M-145)
11. Excess Flow Valve (M-306)

NOTES

a. Weld, heat-fuse, or thread Inlet Service Connections to Main.
b. Install Inlet Service on Main vertically as shown or anywhere on or above the horizontal pipe centerline as required or depth of cover.
c. Threaded Taps in Cast Iron Pipe are permitted without reinforcement to a size not more than twenty-five percent (25%) of the nominal diameter of the pipe except that 1¼" taps are permitted in 4" Cast Iron pipe. In areas where the soil and service conditions may create unusual external stresses on Cast Iron Pipe, Unreinforced Taps may be used only on 6" diameter or larger pipe. On larger Taps, Mechanical Sleeves shall be used.
d. Protective Sleeves (M-135) are required.
e. Excess Flow Valve required on intermediate pressure services only.

FIGURE 3: INSTALLATION OF LOW AND INTERMEDIATE-PRESSURE OUTSIDE SHUT-OFF FOR PLASTIC SERVICE



① Outside Shut-Off (M-61 or M-51)

② Mechanical Coupling (M-122)

③ Plastic Socket Coupling (M-145) or Electrofusion Coupling (M-140)

④ End Protector Bushing (M-118)

⑤ Abandoned Service

⑥ Plastic Service Pipe (M-252)

⑦ Tracer Wire

⑧ Steel Service Pipe (M-251)

⑨ Plastic Pipe Adapter Fitting (M-146)

NOTES

a. Heat-Fuse Plastic Service Pipe to Valve.
b. Thermit-weld Tracer Wire prior to inserting Plastic Pipe, to avoid damage to Plastic Pipe. See C-592 for Thermit-Weld. Use mechanical clamp if inserted first.
c. Use Pipe Dope Sealant at all threaded metal joints.

FIGURE 4: INSTALLATION OF LOW AND INTERMEDIATE-PRESSURE SERVICES THROUGH BUILDING WALL FOR SERVICE REPLACEMENT BY PLASTIC PIPE

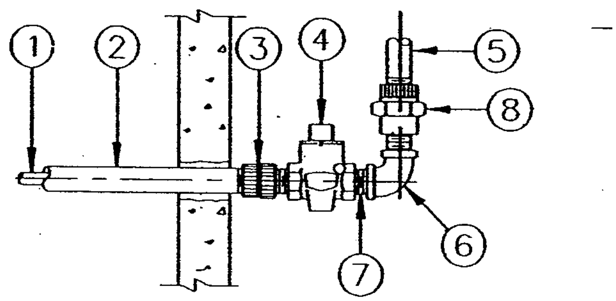


FIGURE 1a: INTERMEDIATE PRESSURE

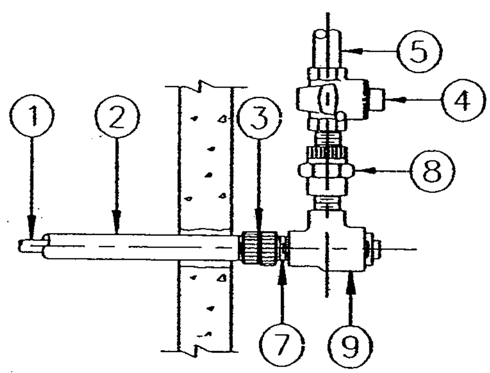


FIGURE 1b: LOW PRESSURE

① Plastic Pipe (Service Inlet) (M-252)

② Abandoned Service

③ Plastic Pipe Adaptor Fitting (Service Head Renewal)(M-146)

④ Inside Shut-Off (M-53)

⑤ Steel Service Pipe (M-251)

⑥ Elbow (M-138)

⑦ Nipple (M-251)

⑧ Insulated Union (M-163)

⑨ Approved Fitting (M-133)

NOTES

a. Use Pipe Dope Sealant at all threaded metal joints.

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[Federal Register: September 15, 2003 (Volume 68, Number 178)]
[Rules and Regulations]
[Page 53895-53902]
From the Federal Register Online via GPO Access [wais.access.gpo.gov]
[DOCID:fr15se03-11]

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket No. RSPA-02-13208; Amdt. 192-93]
RIN 2137-AD01

Pipeline Safety: Further Regulatory Review; Gas Pipeline Safety Standards

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Final rule.

SUMMARY: The Research and Special Programs Administration's (RSPA) Office of Pipeline Safety (OPS) is changing some of its safety standards for gas pipelines. The changes are based on recommendations by the National Association of Pipeline Safety Representatives (NAPSR) and a review of the recommendations by the State Industry Regulatory Review Committee (SIRRC). RSPA/OPS believes the changes will improve the clarity and effectiveness of the present standards.

DATES: This Final Rule takes effect October 15, 2003.

FOR FURTHER INFORMATION CONTACT: L. M. Furrow by phone at 202-366-4559, by fax at 202-366-4566, by mail at U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC, 20590, or by e-mail at buck.furrow@rspa.dot.gov.
SUPPLEMENTARY INFORMATION:

Background

NAPSR is a nonprofit association of officials from state agencies that participate with RSPA/OPS in the Federal pipeline safety regulatory program. RSPA/OPS asked NAPSR to review the gas pipeline safety standards in 49 CFR part 192 and recommend any changes needed to make the standards more explicit, understandable, and enforceable. NAPSR compiled the results of its review in a report titled ``Report on Recommendations for Revision of 49 CFR part 192,'' dated November 20, 1992. The report recommends changes to 40 different sections in part 192.

By the time NAPSR completed its report, RSPA/OPS had published a notice of proposed rulemaking to change many part 192 standards that we considered unclear or too burdensome (Docket PS-124; 57 FR 39572; Aug. 31, 1992). Because a few of NAPSR's recommendations related to standards we had proposed to change, we published the report for comment in the PS-124 proceeding (58 FR 59431; Nov. 9, 1993). The PS-124 Final Rule (61 FR 28770; June 6, 1996) included four of NAPSR's recommended rule changes, and we scheduled the remaining recommendations for future consideration.

Because industry and State views were so divergent on NAPSR's recommendations, in October 1997, the American Gas Association (AGA), the American Public Gas Association (APGA), and NAPSR formed SIRRC to iron out their differences. In a report titled ``Summary Report,'' dated April 26, 1999, SIRRC agreed on all but eight of NAPSR's recommendations that we had scheduled for future consideration. SIRRC also agreed on a NAPSR resolution concerning definitions of ``service line'' and ``service regulator'' that was not among the recommendations in its 1992 report.

Based on our review of NAPSR's recommendations and SIRRC's Summary Report, on November 13, 2002, we published a notice of proposed rulemaking (NPRM) (67 FR 68815). The NPRM invited the public to comment by January 13, 2003, on proposed changes to 21 sections in Part 192. The NPRM also explained why we were not proposing to adopt some of NAPSR's recommendations.

Disposition of Comments

In response to the NPRM, we received written comments from American Gas Association (AGA), Arkansas Public Service Commission (ARPSC), Con Edison (ConEd), Dominion Resources (Dominion), Gas Piping Technology Committee (GPTC), Iowa Utilities Board (Iowa), Metropolitan Utilities District, Michigan Consolidated Gas Company (MichCon), NiSource, Inc. (NiSource), Oleksa and Associates (Oleksa), Peoples Energy (Peoples), Public Service Electric & Gas Company (PSE&G), Southwest Gas Corporation (Southwest), UGI Utilities, Inc. (UGI), and Yankee Gas Services Co. (Yankee). Commenters generally supported the proposed rule changes. However, some commenters opposed particular proposals or suggested alternatives.

This section of the preamble summarizes those latter comments and discusses how RSPA/OPS treated them in developing this Final Rule. This section of the preamble does not address comments that disagree with RSPA's/OPS's decision not to adopt particular NAPSR recommendations or that suggest additional changes to Part 192. If RSPA/OPS has not mentioned a proposed change to Part 192, RSPA/OPS did not receive significant comments on that proposal, and RSPA/OPS are adopting it as final.

Section 192.3, Definitions. RSPA/OPS proposed three changes to Sec. 192.3. First, RSPA/OPS proposed moving the present definition of ``customer meter'' from within the ``service line'' definition to a stand-alone position. Next, RSPA/OPS proposed expanding the ``service line'' definition to include distribution lines that transport gas from a common supply source to adjacent or multiple residential or small commercial customers. Finally, RSPA/OPS proposed a definition of ``service regulator'' that would distinguish customer regulators from regulating stations.

Oleksa suggested the definition of ``customer meter'' would be clearer if RSPA/OPS added the words ``or master meter operator'' after the word ``consumer.'' RSPA/OPS did not consider this comment in finalizing the ``customer meter'' definition because RSPA/OPS did not propose to change the text of the present definition.

AGA, PSE&G, and Peoples commented that the proposed ``service line'' and ``service regulator'' definitions used different terms-- ``meter manifold'' and ``meter header or manifold''--to refer to piping assemblies between a single line and a group of meters. AGA and Peoples preferred the latter term

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because operators may call these assemblies either meter headers or meter manifolds. RSPA/OPS agrees that a single term is appropriate and, because of this comment, used ``meter header or manifold'' in the final definition of ``service line.''

ConEd opposed the proposed definition of ``service line'' because, like the present definition, it includes interior piping that leads to meters in individual apartments or to meters in basements. Primarily because of the difficulty of checking such piping for leaks, ConEd suggested that RSPA/OPS exclude interior piping from the final definition. This comment, however, addresses an issue the NPRM did not cover. RSPA/OPS proposed to broaden the present service line definition, not limit it to outside piping. Therefore, RSPA/OPS has not considered the comment in developing the final definition.

ARPSC commented that, in its experience, lines serving multiple customers are the lines most frequently damaged by third parties, with most damage occurring at burial depths between four and 18 inches. Consequently, ARPSC suggested the burial depth of service lines supplying gas to multiple customers be at least 24 inches. RSPA/OPS did not adopt this comment because increasing burial depth is not generally recognized as one of the best ways to reduce excavation damage to buried utilities. According to a report RSPA/OPS prepared for Congress, Common Ground: Study of One-Call Systems and Damage Prevention Best Practices, the key elements in prevention of excavation damage involve the use of one-call systems, accurate utility mapping, advance notice of excavation, accurate temporary surface marking before excavation, and safe excavation practices.

Regarding the proposed ``service line'' definition, RSPA/OPS asked how it might define the term ``small commercial customers.'' In response, ARPSC said volume should be limited to 10 percent above the volume used by a normal residential customer. Iowa recommended the definitions that operators include in tariffs established under utility regulations. MichCon proposed meter capacity or type or regulator size or type as possible bases for a definition. Finally, NiSource suggested that volume be limited to no more than twice the volume used by the operator's largest residential customer.

Upon further consideration, RSPA/OPS decided not to define ``small commercial customers.'' As the Iowa comment suggests, distribution operators commonly use this term to refer to a class of service offered for sale under state or municipal rate regulations. Because different definitions of the term may be in use, a separate part 192 definition could lead to confusion in identifying a pipeline as a service line. So, without a part 192 definition, the term will apply in part 192 as it does in the industry, to those customers each operator defines as ``small commercial customers'' for tariff purposes.

Section 192.123, Design Limitations for Plastic Pipe. RSPA/OPS proposed to delete the second sentence of Sec. 192.123(b)(2)(i) as obsolete. This sentence allows operators to use plastic pipe manufactured before May 18, 1978, and strength rated at 73 [deg]F at temperatures up to 100 [deg]F. RSPA/OPS also invited operators to tell us whether they still have any stockpiles of this pipe that they plan to use at temperatures above 73 [deg]F. Only one operator responded. NiSource stated that it does not have stockpiles of plastic pipe intended for use at temperatures greater than 73 [deg]F. Since RSPA/OPS received no adverse comment on the proposed rule change, RSPA/OPS adopted it as final.

Section 192.321, Installation of Plastic Pipe; Section 192.361, Service Lines: Installation. Section 192.321(e) requires that in transmission lines and mains, buried plastic pipe that is not encased must have an electrically conductive wire or other means of finding the pipe. Because of reported lightning damage to buried plastic pipe, RSPA/OPS proposed to add the following new requirements to this rule, and to establish similar requirements in Sec. 192.361(g) for plastic service lines:

Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

Regarding proposed Sec. 192.321(e), AGA, NiSource, Oleksa, Southwest, and Yankee were concerned that government inspectors might interpret ``contact with the pipe must be minimized'' too stringently. AGA and NiSource thought inspectors might interpret the term to prohibit contact with the pipe. These commenters also speculated inspectors might interpret the term to preclude trenchless installation of plastic pipe. Oleksa was concerned the proposed wording would require separation of wire from pipe even where total separation is not practicable, as in trenchless installations. Yankee wanted the final rule to state specifically that incidental contact between tracer wire and plastic pipe is all right.

RSPA/OPS thinks these proffered interpretations may be unrealistic because minimized contact implies some contact is permissible. Still, in view of the commenters' concerns, RSPA/OPS has used the following wording in the final rule: ``contact with the pipe must be minimized but is not prohibited.'' RSPA/OPS wants to ensure the rule does not deter the common practice in trenchless installations of randomly taping tracer wire to the pipe to control separation during installation.

AGA, GPTC, Peoples, PSE&G, and Dominion Resources thought proposed Sec. 192.361(g) would require that steel service lines have tracer wire, because the wording was not limited to plastic pipe. To remove this potentiality, RSPA/OPS added the word ``nonmetallic'' to final Sec. 192.361(g).

City Utilities and Southwest were concerned that trying to reduce the risk of lightning damage by separating tracer wire from pipe could lead to inaccurate pipe location and excavation damage. The purpose of tracer wire, as Sec. 192.321(e) states, is to provide a means of locating buried plastic pipe. Neither present nor proposed Sec. 192.321(e) would permit installation of tracer wire so far away from the pipe that it hampers attempts to accurately find the pipe.

MichCon suggested removing ``copper'' from ``coated copper wire'' so the rule would not preclude the installation of other types of corrosion resistant wire. RSPA/OPS did not adopt this comment because the proposed rule would allow operators to use ``other means'' to provide corrosion resistant wire.

Section 192.353, Customer Meters and Regulators: Location. RSPA/OPS proposed to amend Sec. 192.353(a) to emphasize that operators must protect meters and service regulators from vehicular damage. Under the present rule, protection from vehicular damage falls under the general requirement to protect meters and service regulators from ``corrosion and other damage.''

AGA, GPTC, Dominion Resources, Oleksa, Peoples, PSE&G, MichCon, and Yankee were concerned the proposed rule would apply to meters or service regulators installed indoors or other places where there is only a remote chance of vehicular damage. As stated below under the ``Advisory Committee'' heading, the Technical Pipeline Safety Standards Committee had a similar concern about the proposal. The committee recommended RSPA/OPS limit the requirement to outdoor

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installations that are clearly vulnerable to minor impact.

RSPA/OPS said in the NPRM that it expected operators would consider the location of meters and regulators in deciding whether to provide protection from vehicular damage. To insure the final rule reflects this allowance, RSPA/OPS is amending Sec. 192.353(a) to require operators to protect outdoor installations from vehicular damage that may be anticipated. If meters or regulators are installed indoors or installed outdoors in places where anticipating damage from vehicles is not reasonable, no protection is required.

Southwest was concerned that emphasizing vehicular damage would lead to disagreements between government and operators over whether protection is adequate. Nevertheless, such disputes can arise under the present rule, because it requires protection from vehicular damage but does not specify the type or degree of protection. In this situation, operators have discretion to provide whatever type and degree of protection is reasonable under the circumstances. The final rule does not change this discretion. It merely highlights the risk of vehicular damage.

Section 192.457, External Corrosion Control: Buried or Submerged Pipelines Installed Before August 1, 1971; 192.465, External Corrosion Control: Monitoring. RSPA/OPS proposed to amend Sec. 192.457 by removing from paragraph (b) the requirement to use electrical surveys in determining areas of active corrosion, and by removing paragraph (c). Under Sec. 192.465(e), RSPA/OPS proposed to establish more detailed criteria for alternatives to electrical surveys, and to allow operators to use alternatives on distribution lines without first finding that electrical surveys are impractical. In addition, RSPA/OPS proposed to add definitions of ``active corrosion'' (the definition now in Sec. 192.457 (c)), ``electrical survey,'' and ``pipeline environment.''

AGA, Peoples, and GPTC commented that moving the definition of ``active corrosion'' from Sec. 192.457(c) to Sec. 192.465(e) would make Sec. 192.457(b) harder to understand because the term would remain in Sec. 192.457(b). As a remedy, AGA and Peoples suggested adding to Sec. 192.457(b) a cross-reference to the new location of the definition. Peoples also advised making the relocated definition applicable throughout Subpart I rather than just Sec. 192.465(e). GPTC and PSE&G suggested moving the definition to Sec. 192.451, Scope.

Removing Sec. 192.457(c) should not affect Sec. 192.457(b). Under Sec. 192.457(b), the time allowed for initially determining and cathodically protecting areas of active corrosion expired August 1,

1976. And Sec. 192.465(e) regulates all subsequent determinations and protections of areas of active corrosion. So moving the present definition of ``active corrosion'' from Sec. 192.457(c) to Sec. 192.465(e) simply places the definition where it is currently used. With such limited usage, making the definition applicable throughout Subpart I is not necessary.

As previously stated, RSPA/OPS proposed moving the definition of ``active corrosion'' from Sec. 192.457(c) to Sec. 192.465(e). However, RSPA/OPS inadvertently included in proposed Sec. 192.465(e) a similar definition of ``active corrosion'' found in 49 CFR 195.553, which applies to hazardous liquid pipelines. Final Sec. 192.465(e) includes the definition now in Sec. 192.457(c).

The proposed definition of ``electrical survey,'' which SIRRC recommended, is the same definition that applies to hazardous liquid pipelines under 49 CFR 195.553. The definition is based on pipe-to-soil electrical readings over a pipeline. AGA and NiSource recommended changing ``pipe-to-soil'' to ``potential gradient'' to allow the use of ``cell-to-cell'' surveys, which, AGA said, are typically used on bare pipe to identify corrosion activity. MichCon was similarly concerned that other types of electrical corrosion surveys may not qualify under the proposed definition.

RSPA/OPS agrees that cell-to-cell potential testing would not meet the proposed definition of ``electrical survey.'' Nevertheless, proposed Sec. 192.465(e) would not preclude operators from using cell-to-cell testing or any other useful method to find active corrosion areas. To find active corrosion without using an electrical survey, operators could use any means that includes review and analysis of certain maintenance records and the pipeline environment. If augmented by this review and analysis, cell-to-cell testing would qualify for use under proposed Sec. 192.465(e). Therefore, RSPA/OPS did not include the commenters' suggested change in final Sec. 192.465(e).

Southwest thought the term ``closely spaced pipe-to-soil readings'' was unclear, and suggested deleting ``closely spaced.'' However, RSPA/OPS believes the term is consistent with usual industry practices. No other commenter suggested the term would be difficult to apply. In addition, the term is part of the ``electrical survey'' definition in 49 CFR 195.553, which RSPA/OPS adopted without any objection from industry commenters.

Iowa commented erroneously that proposed Sec. 192.465(e) ignores SIRRC's central theme that operators should not have to show that electrical surveys are impractical before using alternative review methods. In fact, proposed Sec. 192.465(e) is faithful to SIRRC's theme. On distribution lines, the proposed rule would allow alternative methods regardless of the practicality of electrical surveys. Only on transmission lines would operators still have to show that electrical surveys are impractical before using alternative methods.

Section 192.479, Atmospheric Corrosion Control: General. RSPA/OPS proposed to revise Sec. 192.479 to require the same level of protection from atmospheric corrosion on new and existing pipelines. However, in certain circumstances, operators would not have to protect pipelines from light surface oxide or from atmospheric corrosion that would not affect safe operation before the next scheduled inspection. A similar regulation is now in effect for hazardous liquid pipelines (49 CFR 195.581). In addition, RSPA/OPS proposed to amend the atmospheric corrosion monitoring requirements of Sec. 192.481 to comport with a similar hazardous liquid pipeline regulation (49 CFR 195.583).

GPTC and PSE&G thought proposed Sec. 192.479 would be clearer if the only exception from the protection requirement were pipe without active corrosion. This comment is similar to SIRRC's suggested change to Sec. 192.479. Our primary reason for not adopting SIRRC's approach was the advantage to industry and government if similar corrosion control regulations governed gas and hazardous liquid pipelines. Another reason was that the proposed exceptions were consistent with SIRRC's approach, since the excepted pipelines would not have active corrosion. So, in keeping with the similar-regulations goal, RSPA/OPS has included the proposed exceptions in final Sec. 192.479.

MichCon opposed the proposed exceptions, arguing that operators should stop further corrosion from even a light surface oxide. MichCon also suggested that cleaning and coating are more effective than assessing whether corrosion would affect safety before the next inspection. In contrast, RSPA/OPS continues to agree with SIRRC that a light surface oxide is a non-damaging form of corrosion that does not need remedial action. The absence of any other negative comment on the proposed oxide exception bolsters this position. Also, even if cleaning and

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coating may be a more effective long-term approach, RSPA/OPS believes operators should have the option of assigning resources to problems that pose a higher near-term risk.

MichCon was concerned that inspecting thermally insulated pipe could destroy the insulation system. It suggested making inspections ``wherever practical'' and sampling pipe through windows cut into the jacketing. MichCon further suggested that the final rule use the term ``electrolyte-to-air interface'' instead of ``soil-to-air interface'' to include other pipeline environments. RSPA/OPS believes MichCon has suggested a reasonable way to meet the proposed requirement to inspect thermally insulated pipe for atmospheric corrosion. The rule is designed to allow operators to choose a satisfactory compliance method. RSPA/OPS left ``soil-to-air interface'' in the final rule because it is one of several specifically-named environments that justify special attention during inspections.

UGI argued that because customer meter sets found inside buildings are generally in non-corrosive environments, the sets do not need inspection for atmospheric corrosion more often than every 5 years. Present Sec. 192.481 calls for inspection at least every 3 years, and RSPA/OPS did not propose to change this interval. Thus, RSPA/OPS did not consider UGI's comment in developing final Sec. 192.481.

AGA suggested RSPA/OPS postpone final action on the proposed revision of Sec. 192.479 until RSPA/OPS addresses issues concerning meters inside buildings and propose other changes to the corrosion control regulations in Part 192. RSPA/OPS has not postponed final action on proposed Sec. 192.479. It is in the interest of pipeline safety overall for RSPA to have similar atmospheric corrosion regulations for gas and hazardous liquid pipelines. Moreover, RSPA/OPS currently has no plans to further revise the Part 192 corrosion control regulations, for RSPA/OPS has closed the previously scheduled revision project (67 FR 74986; Dec. 9, 2002).

Section 192.517, Records. RSPA/OPS proposed to amend Sec. 192.517 to require that operators keep records of required leak tests for at least 5 years. The leak tests are those that Sec. 192.509 requires on pipelines designed to operate below 100 psig, that Sec. 192.511 requires on service lines, and that Sec. 192.513 requires on plastic pipelines.

AGA, Iowa, and Peoples asked us to defer final action on proposed Sec. 192.517 until after RSPA/OPS acts on other changes to Part 192 that SIRRC suggested in a petition for rulemaking dated November 26, 2002. RSPA/OPS has not postponed final action, because RSPA/OPS believes government inspectors need the proposed records now to aid enforcement efforts. More than 10 years ago, NAPSR recognized this need in its ``Report on Recommendations for Revision of 49 CFR part 192.'' If RSPA/OPS decides to make additional changes to Sec. 192.517 because of our consideration of SIRRC's petition, RSPA/OPS will include those changes in a future notice of proposed rulemaking.

MichCon and Southwest objected to the proposed rule. It was unclear to MichCon what information operators would have to record, and Southwest mistakenly assumed the information would be the same as Sec. 192.517 requires for strength tests. As RSPA/OPS stated in the NPRM, the purpose of the proposed records is merely to show that required leak tests have been done, not to retain specific information about the tests. The content of the records would be discretionary. A mere notation showing that required tests were carried out would suffice. Section 192.709 requires records of this type for each patrol, survey, inspection, and test done on transmission lines under Subparts L and M of part 192.

Dominion commented that proposed Sec. 192.517 would be very burdensome, pointing to the large number of leak tests done by customers' contractors on customer-owned service lines. It thought that records of these tests would be difficult for operators to obtain. RSPA/OPS thinks Dominion may have mistaken the type of record needed to comply with proposed Sec. 192.517. Proposed Sec. 192.517 would not require operators to obtain copies of records kept by their customers' contractors. No matter who does the testing, its own workers or its customers' contractors, operators would only have to verify that correct leak tests have been done and then record that fact. Under part 192, distribution operators are already responsible for the correct installation and leak testing of customer-owned service lines. Operators who do not install and test customer-owned service lines themselves must still verify that work done by their customers' contractors meets part 192 requirements. So the burden of keeping a record of leak tests done by customers' contractors should be no greater than for leak tests done by operators themselves.

Section 192.553, General Requirements. Section 192.553(d) requires that a new maximum allowable operating pressure (MAOP) may not exceed the maximum that part 192 allows on a new segment of pipeline constructed of the same materials in the same location. Based on a SIRRC recommendation, RSPA/OPS proposed to replace the reference to part 192 with a reference to ``Sec. Sec. 192.619 and 192.621,'' the sections in part 192 that limit the MAOP of new pipelines.

AGA, Iowa, PSE&G, Peoples, and Southwest asked us to defer final action on the proposed change to Sec. 192.553. They suggested RSPA/OPS wait until after RSPA/OPS acts on SIRRC's suggested change to subpart K, Uprating, included in its November 26, 2002, rulemaking petition. That change would allow operators to increase the MAOP of certain existing low stress pipelines without prior pressure testing.

RSPA/OPS has not postponed final action on proposed Sec. 192.553(d) since the proposal involves only a simple editorial change. However, by taking this action RSPA/OPS is not foreclosing the opportunity for future rulemaking based on SIRRC's suggested change to the uprating requirements. If RSPA/OPS decides to make additional changes to Sec. 192.553(d) because of our consideration of SIRRC's recent petition, RSPA/OPS will include those changes in a future notice of proposed rulemaking.

Section 192.743, Pressure Limiting and Regulating Stations: Testing of Relief Devices. RSPA/OPS proposed to change Sec. 192.743(a) and (b) to allow operators to use calculations to decide if the capacity of relief devices is adequate without first having to conclude that testing the devices is not feasible. RSPA/OPS also proposed editorial changes to Sec. 192.743(c), which requires installation of new or additional devices if the relief capacity of existing devices is inadequate.

Iowa said RSPA/OPS should change Sec. 192.743(c) to allow operators the option of modifying existing devices or associated facilities to provide the required relief capacity. Although this comment concerns an issue RSPA/OPS did not address in the NPRM, RSPA/OPS did not interpret Sec. 192.743(c) to require the installation of unnecessary relief devices. If operators provide adequate relief capacity by modifying existing relief devices or associated facilities, new or additional devices are not necessary.

Section 192.745, Valve Maintenance: Transmission Lines. Section 192.745 requires annual inspection of transmission line valves that operators might need during an emergency. RSPA/OPS proposed to amend this section to require that operators take prompt remedial action to correct any valve found inoperable. Although

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NAPSR had recommended ``immediate'' remedial action, RSPA/OPS proposed prompt action to allow operators some latitude in scheduling maintenance.

AGA, Gulf South, and Southwest were concerned that disagreements would arise between government inspectors and operators over the meaning of ``prompt.'' In this regard, City Utilities suggested RSPA/OPS define ``prompt remedial action'' as not to exceed 6 months. In addition, AGA, GPTC, Gulf South, Peoples, PSE&G, and Yankee suggested that instead of promptly repairing an inoperable valve, operators should have latitude to designate another valve as an emergency valve if the other valve accomplishes the same function as the inoperable valve.

Occasional disagreements over whether remedial action is done promptly may be unavoidable. However, operators can reduce opportunities for disagreements if they assign priority to inoperable emergency valves in their repair schedules. Operators can also look to their experience in promptly correcting corrosion control deficiencies under Sec. 192.465(d). RSPA/OPS decided not to establish a time limit for ``prompt remedial action'' because it could promote unnecessary delay and erode the latitude operators need in scheduling repairs.

Section 192.605(b)(1) requires operators to have procedures for carrying out the valve maintenance requirements of Sec. 192.745. In their procedures, operators identify which valves they must inspect annually because they may need them during an anticipated emergency. If different valves are available for the same function, they only have to identify and inspect one of them to meet Sec. 192.745. So the present rule allows operators latitude to designate an equivalent alternative valve rather than repair an inoperable valve. The proposed rule would not affect this latitude. It would only affect the time to correct an inoperable valve if the operator does not designate an alternative valve. Nevertheless, to assure no one misunderstands the alternative-valve option, RSPA/OPS has included it in final Sec. 192.745. A similar option is in proposed Sec. 192.747 concerning the maintenance of distribution valves.

Section 192.747 Valve Maintenance: Distribution Systems. Section 192.747 requires annual inspection and servicing of each valve that operators may need for safe operation of a distribution system. RSPA/OPS proposed to amend this section to require prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

AGA and Southwest were concerned that disagreements would arise between government inspectors and operators over the meaning of prompt. City Utilities suggested RSPA/OPS define ``prompt remedial action'' as not to exceed 6 months. As RSPA/OPS stated previously regarding similar comments on proposed Sec. 192.745, some disagreement may be inevitable, but operators can reduce the chance of disagreement by prioritizing the repair of inoperable valves. They can also consider their compliance practices in promptly correcting corrosion control deficiencies. As with final Sec. 192.745, RSPA/OPS decided not to set a time limit on ``prompt remedial action'' because it could promote unnecessary delay and erode the latitude operators need in scheduling repairs.

Iowa suggested RSPA/OPS also require prompt remedial action for inaccessible valves. RSPA/OPS addressed the issue of inaccessible safety valves in the NPRM. RSPA/OPS reasoned that if a designated safety valve becomes inaccessible, usually because of paving, the operator should discover the problem no later than the next inspection. Then the operator would have to either correct the problem to enable inspection within the permitted interval or designate an alternative safety valve. Given these circumstances, RSPA/OPS did not propose an additional regulation to insure that operators promptly correct inaccessible safety valves.

Advisory Committee

The Technical Pipeline Safety Standards Committee considered the NPRM and the associated evaluation of costs and benefits at a meeting in Washington, DC on March 27, 2003. This committee is a statutory, advisory committee that advises us on proposed safety standards and other policies for gas pipelines. It has an authorized membership of 15 persons, five each representing government, industry, and the public. Each member has qualifications to consider the technical feasibility, reasonableness, cost-effectiveness, and practicability of proposed pipeline safety standards. A transcript of the meeting is available in Docket No. RSPA-98-4470.

In discussing the NPRM, the committee focused on the proposed change to Sec. 192.353, which emphasizes that operators must protect meters and regulators from vehicular damage. One member was concerned the proposed rule would apply to installations where vehicular damage is unlikely to occur, such as inside buildings or far away from traffic. This member wanted to limit the proposed rule to installations where the potential for vehicular damage is significant. All but one committee member agreed, and the committee suggested changing the proposal to read as follows:

Each meter and service regulator installed inside a building must be installed in a readily accessible location and be protected from corrosion and other damage. Meters installed outside of buildings must also be protected from vehicular damage where they are clearly vulnerable to minor impact.

Subsequently, by unanimous vote, the committee found all the proposed rules and the associated Draft Regulatory Evaluation to be technically feasible, reasonable, cost-effective, and practicable if proposed Sec. 192.353 were changed as the committee suggested. RSPA/OPS considered the committee's advice as set forth above under the heading ``Section 192.353, Customer Meters and Regulators: Location.''

Regulatory Analyses and Notices

Executive Order 12866 and DOT Policies and Procedures. RSPA does not consider this Final Rule to be a significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, the Office of Management and Budget (OMB) has not received a copy of this rulemaking to review. RSPA also does not consider this Final Rule to be significant under DOT regulatory policies and procedures (44 FR 11034: February 26, 1979).

RSPA/OPS prepared a Regulatory Evaluation of the Final Rule, and a copy is in the docket. This regulatory evaluation concludes that because of compliance options, the changes to existing rules may actually reduce operators' costs to comply with those rules.

Regulatory Flexibility Act. This Final Rule is consistent with customary practices in the gas pipeline industry. Therefore, based on the facts available about the anticipated impacts of the Final Rule, I certify, pursuant to Section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this rulemaking would not have a significant impact on a substantial number of small entities.

Executive Order 13175. RSPA/OPS has analyzed this Final Rule according to the principles and criteria contained in Executive Order 13175, ``Consultation and Coordination with Indian Tribal Governments.'' Because the Final Rule will not significantly or uniquely affect the communities of the Indian tribal governments and will not

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impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

Paperwork Reduction Act. Final Sec. Sec. 192.517(b) and 192.605(b)(11) contain minor additional information collection requirements. Section 192.517(b) requires operators to maintain records of certain leak tests for 5 years, and Sec. 192.605(b)(11) requires operators to have procedures for responding promptly to a report of a gas odor inside or near a building. However, RSPA/OPS believes most operators already maintain records of leak tests and have procedures for responding to reports of gas odors inside or near buildings. Also, RSPA/OPS believes the burden of retaining these records is minimal because they largely computerize them. Maintaining these records on a computer disk represents very minimal costs. So, because the additional paperwork burdens of this proposed rule are likely to be minimal, RSPA/OPS believes that submitting an analysis of the burdens to OMB under the Paperwork Reduction Act is unnecessary.

RSPA/OPS did not receive any comments on the burden of proposed Sec. 192.605(b)(11). Comments on the burden of proposed 192.517(b) are discussed above under the heading ``Section 192.517, Records.''

Unfunded Mandates Reform Act of 1995. This Final Rule will not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It would not result in costs of $100 million or more to either State, local, or tribal governments, in the aggregate, or to the private sector, and would be the least burdensome alternative that achieves the objective of the rule.

National Environmental Policy Act. RSPA/OPS has analyzed this Final Rule for purposes of the National Environmental Policy Act (42 U.S.C. 4321 et seq.). Because the Final Rule parallels present requirements or practices, RSPA/OPS has determined that the Final Rule will not significantly affect the quality of the human environment. None of the commenters disputed this conclusion.

Executive Order 13132. RSPA/OPS has analyzed this Final Rule according to the principles and criteria contained in Executive Order 13132 (``Federalism''). The Final Rule does not establish any regulation that: (1) Has substantial direct effects on the States, the relationship between the National government and the States, or the distribution of power and responsibilities among the various levels of government; (2) imposes substantial direct compliance costs on State and local governments; or (3) preempts State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

List of Subjects in 49 CFR Part 192

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

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For the reasons discussed in this preamble, RSPA amends 49 CFR Part 192 as follows:

PART 192--TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

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1. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

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2. Amend Sec. 192.3 by adding in alphabetical order definitions of ``customer meter'' and ``service regulator'' and by revising the definition of ``service line'' as follows:

Sec. 192.3 Definitions.

* * * * *

Customer meter means the meter that measures the transfer of gas from an operator to a consumer.

* * * * *

Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Service regulator means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

* * * * *

Sec. 192.123 [Amended]

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3. Remove the second sentence in Sec. 192.123(b)(2)(i).

Sec. 192.197 [Amended]

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4. In Sec. 192.197(a), remove the term ``under 60 p.s.i. (414 kPa) gage'' and add the term ``60 psi (414 kPa) gage, or less,'' in its place.

Sec. 192.285 [Amended]

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5. In Sec. 192.285(d), remove the term ``his'' and add the term ``the operator's'' in its place.

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6. Revise Sec. 192.311 to read as follows:

Sec. 192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

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7. Revise Sec. 192.321(e) to read as follows:

Sec. 192.321 Installation of plastic pipe.

* * * * *

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

* * * * *

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8. Revise the first sentence of Sec. 192.353(a) to read as follows:

Sec. 192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. * * *
* * * * *

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9. Add Sec. 192.361(g) to read as follows:

Sec. 192.361 Service lines: Installation.

* * * * *
(g) Locating underground service lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with Sec. 192.321(e).

Sec. 192.457 [Amended]

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10. Amend Sec. 192.457 as follows:
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a. In paragraph (b)(3), remove the second sentence; and
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b. Remove paragraph (c).

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11. Revise Sec. 192.465(e) to read as follows:

Sec. 192.465 External corrosion control: Monitoring.

* * * * *
(e) After the initial evaluation required by Sec. Sec. 192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its

[[Page 53901]]

unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. In this section:
(1) Active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

(2) Electrical survey means a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

(3) Pipeline environment includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

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12. Revise Sec. 192.479 to read as follows:

Sec. 192.479 Atmospheric corrosion control: General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will--

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

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13. Revise Sec. 192.481 to read as follows:

Sec. 192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore................................	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore...............................	At least once each calendar year, but with intervals not exceeding 15 months

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

Appendix 7

Changes to Natural Gas Pipeline Safety Regulations
Effective October 15, 2003

Prepared By

Susan A. Moore
Van Ness Feldman, P.C.

October 21, 2003

On September 15, 2003, the Office of Pipeline Safety (OPS) issued a final rule modifying several of its natural gas pipeline safety standards.[1] The regulations became effective on October 15, 2003. The changes are based on recommendations made by the National Association of Pipeline Safety Representatives and a review of the recommendations by the State Industry Regulatory Review Committee (SIRRC). According to OPS, the changes will improve the clarity and effectiveness of the existing standards.

The revised rules affect numerous pipeline safety regulations pertaining to natural gas distribution and to transmission lines. Provisions that primarily affect distribution lines include (1) an expanded definition of "service line;" (2) design limitations for plastic pipe; and (3) modified installation requirements for plastic pipes. Other revised regulations, such as those pertaining to monitoring external corrosion control, atmospheric corrosion control requirements, leak test record keeping, and valve maintenance, apply to both gas distribution and transmission pipelines.

The following chart illustrates how the rules have been modified (with previous regulatory language indicated by a strike-through and with new language underscored), and provides relevant OPS commentary explaining the reasons for the revisions.

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1 **Final Rule, Pipeline Safety:** Further Regulatory Review; Gas Pipeline Safety Standards, 68 Fed. Reg. 53,895 (Sept. 15, 2003).

§ 192.3 Definitions	
Revised Regulatory Language: *Customer meter* means the meter that measures the transfer of gas from an operator to a consumer. *Service line* means a distribution line that transports gas from a common source of supply ~~(1) to customer meter or the connection to a customer's piping, whichever is farther downstream, or, (2) the connection to a customer's piping if there is no customer meter.~~ to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter. ~~A customer meter is the meter that measures the transfer of gas from an operator to a consumer.~~ *Service Regulator* means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulatory may serve one customer or multiple customers through a meter header or manifold.	**Reasons for Revision:** • Definition of "customer meter" is now a stand-alone definition, rather than embedded in the definition of "service line." • Definition of "service line" is expanded to include distribution lines transporting gas from a common supply source to adjacent or multiple residential or small commercial customers. The revised definition means that lines transporting gas from a common supply source to multiple residential or small commercial customers will not be considered "mains" and will be exempt from pipeline safety regulations applicable to mains. Proposed Rule, 67 Fed Reg. 68,815-16 (Nov. 13, 2002). • OPS rejected the argument that lines serving multiple customers should be buried at a depth of at least 24 inches. "[I]ncreasing burial depth is not generally recognized as one of the best ways to reduce excavation damage to buried utilities." Rather, citing the *Common Ground: Study of One-Call Systems and Damage Prevention Best Practices* report, OPS stated "key elements" to preventing excavation damage "involve the use of one-call systems, accurate utility mapping, advance notice of excavation, accurate temporary surface marking before excavation, and safe excavation practices." Final Rule, 68 Fed. Reg. 53,895-96 (Sept. 15, 2003).

§ 192.123(b)(2)(i) Design limitations for plastic pipe **Revised Regulatory Language:** (b) Plastic pipe may not be used where operating temperatures of the pipe will be . . . . (2) Above the following applicable temperatures: (i) For thermoplastic pipe, the temperature at which the long-term hydrostatic strength used in the design formula under § 192.121 is determined. ~~However, if the pipe was manufactured before May 18, 1978 and its long-term hydrostatic strength was determined at 73degrees F (23 degrees C) it may be used at temperatures up to 100 degrees F (66 degrees C).~~	**Reasons for Revision:** • Pipeline operators apparently do not have plastic pipe of this vintage stockpiled in their inventories. 67 Fed. Reg. at 68,817; 68 Fed Reg. at 53,896.
§ 192.197(a) Control of the pressure of gas delivered from high-pressure distribution systems **Revised Regulatory Language:** (a) If the maximum actual operating pressure of the distribution system is under 60 psi (414 kPa) gage, <u>or less,</u> and a service regulator having the following characteristics is used, no other pressure limiting device is required: . . .	**Reasons for Revision:** • This change eliminates a discrepancy with § 192.197(b). 67 Fed. Reg. at 68,817.
§ 192.311 Repair of plastic pipe **Revised Regulatory Language:** Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired ~~by a patching saddle~~ or removed.	**Reasons for Revision:** • OPS explained that there are various methods of accomplishing a safe repair and OPS did not think it necessary to limit them. In addition, § 192.703(b) prohibits use of any method that would result in an unsafe condition. 67 Fed. Reg. at 68,818.

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§ 192.321 Installation of plastic pipe
§ 192.361(g) Service lines: Installation

Revised Regulatory Language (§ 192.321):

(a) – (d) [unchanged]
(e) Plastic pipe that is not encased must have an electrically ~~conductive~~ conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

Revised Regulatory Language (§ 192.361(g)):

(a) – (f) [unchanged]
(g) Locating underground service lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with § 192.321(e).
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Reasons for Revision:

• OPS explained that this change is intended to reduce the likelihood that highly charged tracer wire will harm buried plastic pipe but nevertheless ensure that the tracer wire remains a reliable and accurate method of locating buried plastic pipe. 67 Fed. Reg. at 68,818; 68 Fed Reg. at 53,896.
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§ 192.353(a) Customer meters and regulators: Location

Revised Regulatory Language:

(a) Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

(b), (c), and (d) are unchanged.
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Reasons for Revision:

• Revision highlights the risk of vehicular damage and is intended to emphasize that operators must protect meters and service regulators from vehicular damage that may be anticipated. 68 Fed. Reg. 53,896-97.

• Operators' discretion to provide whatever type and degree of protection is reasonable under the circumstances remains unchanged under the revised rule. <u>Id.</u> at 53,897.

• "Although § 192.353(a) affects design and does not apply to pipelines constructed before it went into effect, protection from
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	vehicular damage is also a safety concern on earlier constructed pipelines. These pipelines, however, are subject to the general maintenance standard of § 192.703(b), which requires operators to correct any pipeline that becomes unsafe. If the safety of a meter set is jeopardized by vehicular traffic, the operator would have to take action under § 192.703(b) to correct the problem." 67 Fed. Reg. at 68,818-19.
§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971 **Revised Regulatory Language**: (a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements. (b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found: (1) Bare or ineffectively coated transmission lines. (2) Bare or coated pipes at compressor, regulator, and measuring stations. (3) Bare or coated distribution lines. ~~The operator shall determine the areas of active corrosion by electric survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.~~ ~~(c) For the purpose of this subpart, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.~~ *[§ 192.457(c) moved to § 192.465]*	**Reasons for Revision:** • OPS explained that this sentence is removed because the time for completing the initial evaluation of the need for corrosion control has expired. 67 Fed. Reg. at 68,819. • Moving the definition of active corrosion to § 192.465 places it in the section where it is used. 68 Fed. Reg. at 53,897.

§ 192.465(e) External corrosion control: Monitoring

Revised Regulatory Language:

(a) [requires cathodically protected pipelines to be tested once per year, at intervals not exceeding 15 months]

(b) [requires cathodic protection rectifiers to be inspected 6 times each calendar year, but with intervals not to exceed 2½ months]

(c) [requires electrical check of reverse current switches, diodes, and interference bonds whose failure would jeopardize structure protection 6 times each year, but with intervals not to exceed 2½ months]

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by ~~paragraphs (b) and (c) of~~ §§ 192.455(b) and (c) and ~~paragraph (b) of §~~ 192.457(b), each operator ~~shall~~ must, not less than every ~~at intervals not exceeding~~ 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator ~~shall~~ must determine the areas of active corrosion by electrical survey~~,~~. However, on distribution lines and ~~or~~ where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipeline inspection records, and the pipeline environment. In this section: ~~, by the study of corrosion and leak history records, by leak detection survey, or by other means.~~

(1) *Active corrosion* means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

(2) *Electrical survey* means a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

(3) *Pipeline environment* includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

Reasons for Revision:

- "RSPA/OPS agrees that cell-to-cell potential testing would not meet the proposed definition of 'electrical survey.' Nevertheless, proposed § 192.465(e) would not preclude operators from using cell-to-cell testing or any other useful method to find active corrosion areas. To find active corrosion without using an electrical survey, operators could use any means that include review and analysis of certain maintenance records and the pipeline environment. If augmented by this review and analysis, cell-to-cell testing would qualify for use under proposed § 195.465(e)." 68 Fed. Reg. at 53,897.

- On distribution lines, the rule would permit alternative review methods regardless of whether electrical surveys are practical. Operators must show that electrical surveys are impractical before using alternative review methods only on transmission lines. 68 Fed. Reg. at 53,897.

§ 192.479 Atmospheric corrosion control: General	
Revised Regulatory Language: ~~(a) *Pipelines installed after July 31, 1971.* Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.~~ ~~(b) *Pipelines installed before August 1, 1971.* Each operator having an above-ground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall –~~ ~~(1) Determine the areas of atmospheric corrosion on the pipeline;~~ ~~(2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and~~ ~~(3) Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.~~ <u>(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.</u> <u>(b) Coating material must be suitable for the prevention of atmospheric corrosion.</u> <u>(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will –</u> <u>(1) Only be a light surface oxide; or</u> <u>(2) Not affect the safe operation of the pipeline before the next scheduled inspection.</u>	**Reasons for Revision:** • Revised § 192.479 will require the same level of protection from atmospheric corrosion regardless of when the pipeline was installed. 67 Fed. Reg. at 68,820-21; 68 Fed Reg. at 53,897. • OPS stated that this rule now comports with corrosion control requirements applicable to hazardous liquids pipelines (§ 195.581). 67 Fed. Reg. at 68,820. • OPS rejected a comment that had suggested that operators should stop further corrosion from even a light surface oxide. Rather, OPS stated its agreement with SIRRC that a light surface oxide is a non-damaging, form of corrosion that does not require remedial action. 68 Fed. Reg. at 53,897. • OPS also rejected a suggestion that cleaning and coating are more effective than assessing whether corrosion would affect safety before the next inspection. Rather, OPS stated its agreement with SIRRC that light surface oxide is a non-damaging form of corrosion that does not need remedial action. Moreover, OPS stated that, even if cleaning and coating were more effective long-term approaches, operators should have the option of assigning resources to problems that pose a higher near-term risk. 68 Fed. Reg. at 53,898.

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§ 192.481 Atmospheric corrosion control: Monitoring

Revised Regulatory Language:

~~After meeting the requirements of § 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and at least once each calendar year, but with intervals not exceeding 15 months, for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.~~

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located onshore, then the frequency of inspection is: at least once every 3 years, but with intervals not exceeding 39 months.

If the pipeline is located offshore, then the frequency of inspection is at least once each calendar year, but with intervals not exceeding 15 months.

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by § 192.479.

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Reasons for Revision:

• In response to a comment that the final rule use the term "electrolyte-to-air interface" instead of "soil-to-air interface" to include other pipeline environments, OPS stated that it retained "soil-to-air interface" because it is one of several specifically-named environments that justify special attention during inspections. 68 Fed. Reg. at 53,898.

• § 192.481 is amended to be consistent with monitoring requirements applicable to hazardous liquids pipelines. 67 Fed. Reg. at 68,820; 68 Fed Reg. at 53,898.

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§ 192.517 Records

Revised Regulatory Language:

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:
(1)~~(a)~~ The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

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Reasons for Revision:

• The "purpose of the proposed records is merely to show that required leak tests have been done, not to retain specific information about the tests. The content of the records would be discretionary. A mere notation showing that required tests were carried out would suffice." 68 Fed. Reg. 53,898.

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